Report and Recommendations of the Cost Analysis Subgroup

Docket 7523

August 28, 2009

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I. Summary[1]

On July 10, 2009, the participants in Docket 7523 and 7533 organized themselves into subgroups, including the Cost Analysis Subgroup, to facilitate the resolutions of issues in order to meet statutory deadlines established for this investigation. This is the final report of the Cost Analysis Subgroup in the Vermont Public Service Board's Docket 7523.

The Subgroup efforts focused on assisting the Board in meeting its statutory responsibility for price determinations by modeling the generic costs of different renewable resources. This report presents the results of modeling efforts that included an initial effort to establish a model and subsequent efforts to establish appropriate model inputs and assumptions. The report serves to identify the areas of agreement and divergence relative to the rate determinations that are required of the Public Service Board in order to fulfill their responsibilities pursuant to Act 45 of 2009 to determine whether the rates contained in statute represented a "reasonable approximation" of the costs using the criteria contained in statute. Those interested in following the detailed trail of resources and meetings that led to this report should go the Board website devoted to this Subgroup.[2]

While the law contained only a requirement for the Public Service Board to essentially verify the rates contained in statute, the actual modeling of costs and associated development of assumptions was deemed necessary by the subgroup to both assist the Board in making the determinations and to provide foundation for an alternative, if indeed the Board concluded that the statutory rates did not meet the standard. A set of cost-based assumptions was developed for all the technologies and size categories listed in the law except for the small wind (less than15kW projects). The limitations of time, however, did not permit an opportunity to test the assumptions comparable to that which may be possible with more time and as can be expected for the January 15, 2009 determinations in Docket 7533.

Those participating in the Subgroup have contributed or provided comments on this report and will be asked to supplement and respond to the issues that have been highlighted in the report.

The approach taken by the Subgroup was to first establish a model that would be used to develop the generic cost estimates. A cash flow model was developed and adjusted collaboratively by the Subgroup after initial contributions by Green Mountain Power and the Board's Technical Advisor to the Project. The final stages of the modeling were performed by the Department of Public Service. Two sets of input assumptions were used in developing two sets of cost estimates. The "***initial"*** input assumptions that were used by the Subgroup reflected input assumptions received primarily from the project developers or their representatives. A second group of assumptions were provided by the Department of Public Service, and included information gleaned from the Clean Energy Development Fund applications.

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[1] Various Subgroup participants and individuals outside the subgroup contributed to the development of the Subgroup report. Developers and others providing recommended inputs were provide space to describe the resource, the inputs to the model and the foundation for those inputs in Appendix B, and are listed next to the header for their contribution. Ken Jones of the Vermont Department of Taxes assisted with the development of the discussion of tax issues that formed the basis of the discussion in the text of the report. John Becker of the Department of Public Service assisted with the discussion of grants that immediately follows the discussion of taxes.

[2] See, http://psb.vermont.gov/docketsandprojects/electric/7523/costanalysis

Modeling Results

As described in Appendix A, the Subgroup relied on a Cash Flow model that was used to establish the price which yielded an after tax return on equity of 12.13 percent, equal to the highest allowed return available to an investor owned electric distribution utility in Vermont. This is the minimum return authorized by statute before adjustments. As presented below, two sets of modeling runs and cost estimates were developed by the group. The ***initial*** runs were the product of submissions that were received largely from developers and their representatives and are presented in Table 1. The second set of **DPS** modeling runs for wind, solar, hydro, farm methane and landfill gas projects were provided pursuant to the recommended inputs from the Vermont Department of Public Service and are presented in Table 2.

As described further in the report, the modeling runs reflected here represent a generally consistent set of assumptions applied to the cost of equity and, more generally to the determination of the cost of capital. In at least one instance, this recommendation conflicted with the specific recommendations of developers.[3] With the exception of farm methane, there was no need to include offsetting values for the price of the Renewable Energy Credits ("RECs") because the rights to the attributes of the energy associated with the RECs was provided to the purchasing retail distribution utilities. Farm methane estimates also included offsetting benefits of both REC sales and other benefits of improved farm operations as offsets to revenue requirements for the system.

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[3] See capital structure recommendations of for Solar provided by REV.

Table 1

Key Assumptions and Modeling Results by Resource Category and Size

Initial Runs

Technology	Hydro	Wind			Biomass
Net Capacity (kW)	1,278	1,500	100	15	100
Installed Capital Cost ($/kW)*	$ 4,173	$ 3,000	$ 5,850		
Fixed O&M ($/kW-year)	$ 162	$ 72	$ 123		
Offsetting Revenue ($)***					
Capacity Factor	44.9%	26.6%	23.8%		
Modeled Price ($/MWh)	$ 150	$ 126	$ 269		
Default Price per Act 45 ($/MWh)	$ 125	$ 125	$ 125	$ 200	$ 125

Technology	Solar PV			Landfill Gas	Ag Methane		
Net Capacity (kW)	15	150	500	132	300	65	35
Installed Capital Cost ($/kW)*	$ 8,140	$ 7,170	$ 6,850	$ 4,818	$ 7,628	$ 12,307	$ 15,714
Fixed O&M ($/kW-year)	$ 120	$ 106	$ 102	$ 1,116	$ 767	$ 1,801	$ 2,936
Offsetting Revenue ($)***					$ 95,000	$ 22,500	$ 12,750
Capacity Factor	13%	13%	13%	90%	76.5%	76.5%	76.5%
Modeled Price ($/MWh)	$ 557	$ 493	$ 471	$ 254	$ 175	$ 345	$ 554
Default Price per Act 45 ($/MWh)	$ 300	$ 300	$ 300	$ 120	$ 120	$ 120	$ 120

The alternative to the DPS “least-cost” approach, which would base rates on the most cost efficient projects, creating rates that favor the largest, i.e. 2.2 MW, wind, solar, biomass and hydro projects, is to create more granular incentive bands that provide a better match for the variation in costs for projects across not just different technologies, but different capacity sizes within those technologies. Northern Power, the Department of Agriculture and REV all support this “diversity” approach of sub-capacity price bands. Policy experts, including NREL who presented in front of the PSB at the July 10 workshop, presented this approach as a means to increase uptake in projects of different capacities, to foster local energy generation, to disperse projects in order to reduce interconnection and transmission constraints as well as losses due to transmission and distribution, to create innovation and further costs reductions within those smaller sizes and to encourage the local job creation of developers and installers these smaller projects support. Northern Power submitted a research brief entitled “Granularity Issue: Brief on Cost Efficiency and FIT Best Practices_8062009” that can be found at http://psb.vermont.gov/docketsandprojects/electric/7523/costanalysis.

Table 2

Key Assumptions and Modeling Results by Resource Category and Size

DPS Model Runs

Technology	Hydro	Wind			Biomass
Net Capacity (kW)	1278	1500	100	15	
Installed Capital Cost ($/kW)	$4,173	$ 3,000	$ 5850		
Fixed O&M ($/kW-year)	$162	$ 72	$ 123		
Offsetting Revenue ($)					
Capacity Factor	44.9	26.6%	23.8%		
Modeled Price ($/MWh)	132	111	171		
Default Price per Act 45 ($/MWh)	$ 125	$ 125	$ 125	$ 200	$ 125

Technology	Solar PV				Landfill Gas	Ag Methane		
Net Capacity (kW)	15	115	500	2200	123		300	
Installed Capital Cost ($/kW)	*$ 7,10 0*	6,260	5,960	3960	4818		7,628	
Fixed O&M ($/kW-year)	105	94	89	61	591		767	
Offsetting Revenue ($)							95,000	
Capacity Factor	13%	15%	15%	15%	15%		76.5%	
Modeled Price ($/MWh)	$ 368	271	259	177	129		149	
Default Price per Act 45 ($/MWh)	$ 300	$ 300	$ 300	$ 300	$ 120		$ 120	

Note: Shaded blocks signify areas where the DPS does not support granularity for the Sept. 15, 2009 determinations. Light shading with figures indicates where the DPS has provided modeling support for figures different than those provided in the ***Initial*** Model Runs and generally below the presumptive rates contained in statute.

As the figures show, the Department recommends that, in general, the Board's determinations guided by the modeling, rely on the largest, and generally the most cost-effective technology for purposes of the rate determinations within the boundaries permitted in the law (generally 2.2 MW, but also 15 kW for wind).

II. Background

A. Board Investigation Opened Pursuant to Act 45

Act 45 became effective on May 27, 2009. On June 6, 2009, the Public Service Board opened Docket 7523 to investigate the development of standard offer prices for qualifying renewable generation under the Sustainably Priced Energy Enterprise Development ("SPEED") program. This investigation was initiated to address the requirement in the Vermont Energy Act of 2009 ("Act 45" or "Act"), codified in 30 V.S.A. § 8005(b)(2), that the Board open and complete, by September 15, 2009, a "noncontested case docket" to determine whether the prices established by the Act "constitute a reasonable approximation of the price that would be paid applying the criteria" established by the Act. Our Order stated that Docket No. 7523 would address the review of the Act's standard offer prices and, if the prices are not a reasonable approximation, set interim prices by September 15, 2009.

Four Subgroups were established at the July 10, 2009 Workshop to help facilitate resolution of the issues identified. The Cost Analysis Subgroup was charged with identifying and proposing tools and information sources to be relied upon in meeting the Board's obligation to determine rates that represent a "reasonable approximation" of "a generic cost, based on an economic analysis, for each category of generation technology that constitutes renewable energy." (30 VSA 8005 b.(2)(B)(ii)) The Subgroup was also charged with identifying and proposing tools and information sources to be relied on in setting the longer term prices "to be paid to a plant owner under a standard offer" needed by January 15, 2010.

This report summarizes the process and recommendations of that Subgroup, including areas of agreement and divergent views among the subgroup members. This subgroup was chaired by Board staffer J. Riley Allen. John Dalton, who was retained by the Public Service Board as its technical advisor, also served as a resource to the Subgroup. Other members or participants in subgroup meetings are listed in Appendix D. This group met on seven occasions between July 23, 2009 and August 27, 2009. Materials developed for this group and by this group are available on the Board’s web site at http://psb.vermont.gov/docketsandprojects/electric/7523/costanalysis.

B. Requirements of Act 45 Related to The Costs Analysis Subgroup

The Act establishes certain presumptive rates described below and provides guidance to the Board in determining whether the presumptive rates do not reasonably approximate the costs of each category of resource. Specifically, that Act states the following:

> Until the board determines the price to be paid to a plant owner in accordance with subdivision (2)(B) of this subsection, the price shall be:
> (i) For a plant using methane derived from a landfill or an agricultural operation, $0.12 per kWh.
> (ii) For a plant using wind power that has a plant capacity of 15 kW or less, $0.20 per kWh.
> (iii) For a plant using solar power, $0.30 per kWh.
> (iv) For a plant using hydropower, wind power with a plant capacity greater than 15 kW, or biomass power that is not subject to subdivision (2)(A)(i) of this subsection, a price equal, at the time of the plant’s commissioning, to the average residential rate per kWh charged by all of the state’s retail electricity providers weighted in accordance with each such provider’s share of the state’s electric load.

The Act requires the Public Service Board to open and complete a noncontested case docket to accomplish each of the following tasks by September 15, 2009:

> (I) Determine whether there is a substantial likelihood that one or more of the prices stated in subdivision (2)(A) of this subsection do not constitute a reasonable approximation of the price that would be paid applying the criteria of subdivision (2)(B)(i).
> (II) If the board determines that one or more of the prices stated in subdivision (2)(A) of this subsection do not constitute such an approximation, set interim prices that constitute a reasonable approximation of the price that would be paid applying the criteria of subdivision (2)(B)(i).
> Once the board sets such an interim price, that interim price shall be used in subsequent standard offers until the board sets prices under subdivision (B)(iii) of this subdivision (2).

In establishing the rates, the Act specifies that

> In conducting such an economic analysis the board shall: (aa) Include a generic assumption that reflects reasonably available tax credits and other incentives provided by federal and state governments and other sources applicable to the category of generation technology. For the purpose of this subdivision (2)(B), the term "tax credits and other incentives" excludes tradeable renewable energy credits. (bb) Consider different generic costs for subcategories of different plant capacities within each category of generation technology.

The Act also specifies the rate of return on equity and gives the Board discretion to adjust the generic costs "to ensure the price provides sufficient incentive for rapid development, without exceeding that amount.

> (II) The board shall include a rate of return on equity not less than the highest rate of return on equity received by a Vermont investor-owned retail electric service provider under its board-approved rates as of the date a standard offer goes into effect. (III) The board shall include such adjustment to the generic costs and rate of return on equity determined under subdivisions (2)(B)(I) and (II) of this subsection as the board determines to be necessary to ensure that the price provides sufficient incentive for the rapid development and commissioning of plants and does not exceed the amount needed to provide such an incentive."[4]

C. Approaches to Estimating Costs

1. General Modeling and Input Assumptions

The approach taken to estimating the costs was to develop estimates of costs based on a pro forma model of costs and revenues necessary to produce a rate of return equal to or consistent with the statutory standards. For purposes of the modeling, the project developers were assumed to be for-profit institutions that could take full advantage of available state and federal tax incentives encouraging the development of such projects.[5] Not-for-profit institutions may also potentially be responsible for projects, however, developments by these entities were not expressly modeled due to time limits and, in part, because such institutions have corollary opportunities to offset costs (e.g., lower cost capital requirements, available grants, and potentially development costs).

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[4] Section 8005(b)(2)(B)(III).

Perhaps the issue that received the most discussion and range of opinions within the Subgroup were those associated with the extent to which the Board should include project size or granularity considerations in their September 15, 2009 determinations.

Average Retail Residential Rate

In addition to other Subgroup determinations, the Cost Analysis group agreed upon a method for calculating the average retail residential rate.

The development of such a rate was necessary because certain statutory presumptive rates (wind over 15 kW, hydro power and biomass (other than methane derived from a landfill or agricultural operations) were based on such a determination. In the end, the Department calculated a rate of 12.5 cents per kWh based on an estimate of all residential rate revenues excluding revenues associated with the customer charge divided by all residential sales (kWh). A spreadsheet showing the calculation is available on the Board’s web site.[6]

Some concern was expressed within the group for reliance on a literal interpretation of existing language of Act 45 establishing “a price equal, at the time of the plant’s commissioning, to the average residential rate per kWh charged by all of the state’s retail electricity providers weighted in accordance with each such provider’s share of the state’s electric load.” Such a price term would raise concerns to potential project lenders because of uncertainty surrounding the rate in relation to the timing of commissioning. A literal rate determination is also potentially unknowable because it would depend on an uncertain denominator (provider loads) that presumably could only be calculated well after the establishment of a contract. The Subgroup recommended that in place of this, the Board establish that the default rate should be equal to the rate of $125 per MWh as calculated by the Department.

Project Size (Granularity)

As indicated above, one issue that received considerable attention and divergent opinions was on the topic of “granularity” or project size considerations when the Board considers its responsibilities under statute to “consider different generic costs for subcategories of different plant capacities within each category of generation technology.” (Subsection 8005(b)(2)(B)(i)(bb)) On the one hand, members of the Subgroup argued that the legislative intent was to encourage the development of resource categories to cover a range of capacity sizes. Indeed, this intent is demonstrated by the separate determinations required by the Board for two sizes of wind generation technology. It is reflected in the language expressly providing the Board discretion to further differentiate pursuant to the above subsection.

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[5] However, even not-for-profit institutions could potentially take advantage of the grant programs available, such as Vermont's Clean Energy Development Fund. Such grants were not assumed available to for-profit institutions because the receipt of such grants generally compromise the ability of the recipient to receive the investment tax credits.

[6] http://psb.vermont.gov/docketsandprojects/electric/7523/costanalysis under the "Materials" section.

There is broad agreement that scale economies or cost efficiencies favor larger projects for each technology. For wind it is likely more pronounced than solar, and potentially others. In order to accurately reflect a "cost plus return" for different size projects (Act 45 allowed the Board to differentiate size projects across a broad range). Northern Power argues that for wind it would be fair to propose three tiers in the report below Table 3 on wind: 0-15kW; 16kW-100kW; 101kW-500kW; and 500kW-2200kW.[7]

The Department argues for a “cautious approach” to setting rates in the best interest ratepayers here. There seems to be significant interest among developers to respond to the pending program offering and other jurisdictions have been “swamped” with applications. Setting rates at the most cost efficient range of the cost curve will require cost efficiency from developers. The Department also argues that the fact that the Board is charged with such considerations, they are not require to adopt such differentiation. Indeed there is time for such consideration for the January 15, 2010 determinations. It would, however, be inappropriate at this juncture given the task at hand to consider the reasonableness of the presumptive statutory rates for September 15. The Department argues that at this stage the Board should focus its attention on the most cost-effective size of each technologies generally available within the technology groupings established in statute. To do otherwise would result in a windfall for the most efficient technologies.

We expect the Department and others that are taking firm positions on the issue of granularity in relation to the September 15, 2009 determinations to supplement this filing with formal comments on August 28, 2009.

Cost of Capital

The cost of capital or return on investment for these projects is comprised of both a debt and equity component. Key assumptions here include the capital structure, the cost of debt, and the cost of equity.

With respect to the capital structure a range of views were presented suggesting that the capital structure for individual technology categories should be 100% equity financed, to a view that the financing structure should include as much as 70% debt.

For purposes of the modeling, a debt structure of 70/30 (70% debt and 30% equity) were assumed for the model runs in almost all instances, except where the debt coverage ratio (the ratio of EBITDA, earnings before interest, taxes, depreciation and amortization and debt service (interest and principal payments)) fell, on average, below 1.5.[8] This assumption was based on the view that those project developers that were using project financing would be able to increase the after tax cash flows of their projects by increasing the share of debt, up to roughly 70% but in some cases only 60%, when the average debt coverage ratio was well above 1.5.

For the DPS model runs the debt to equity ratio was adjusted to ensure the project remained cash flow positive for all years (except in the year of inverter replacement for solar) and the average debt coverage ratio was well above 1.5. In order to achieve this for some technologies the debt to equity ratio approached 50/50.

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[7] Northern Power detailed its position and support for that position in a submission on August 6, 2009 and is available in the "Materials" portion of the Board's web site dedicated to the Cost Analysis Subgroup http://psb.vermont.gov/docketsandprojects/electric/7523/costanalysis.

[8] In addition, the smaller solar PV and Ag methane projects were not assumed to use non-recourse debt which is typically used in project finance and as such didn't require such a debt coverage ratio. These projects are more likely to be financed using the real property and improvements as the collateral.

Upon review of the relevant Board Order, it was established that the return on equity meeting the statutory requirements was 12.13 percent.[9]

Assumptions Regarding Cost and Term of Debt Financing

The cash flow modeling required that assumptions be made regarding the cost of debt and the term over which the debt would be repaid. There was a wide divergence of opinions among Subgroup members regarding the appropriate assumptions for each. These are discussed below along with the rationale for the assumptions used.

The cost of debt (interest rate) was assumed to be 7%. The initial modeling using proponent assumptions assumed an 18-year loan, except for the farm methane projects which assumed a seven-year term. The seven-year term for farm methane projects reflects that the loan is secured on the value of the farm. For its modeling the DPS typically assumed that the term of the loan was consistent with the contract term. At least one project proponent asserted that an 8% cost of debt was more realistic in the current credit environment. A number of parties suggested a shorter term loan was appropriate.

For most technologies (all except farm methane) the cash flow modeling assumed that developers would finance their projects with non-recourse debt. Under such a project finance structure lenders will establish the cost of debt based on their assessment of the project's overall risk and general credit market conditions at the time of the financing. With the program underpinned by legislation and a Board order approving the contract, there is likely to be relatively limited regulatory risk. The ultimate buyers for the power are the Vermont Distribution Utilities. There isn't a single counterparty; this should reduce the perceived credit risks to the seller. Therefore, it is believed that the standard offer contract will not be viewed as unduly risky by lenders.

A more challenging question is the likely condition of credit markets when these projects are financed. Conditions in the credit markets have improved significantly over the last several months. A significant number of electric utilities have issued debt at reasonable terms and high quality generation projects (i.e., fully contracted with attractive credits) are getting financed. While the tenors (term of debt) of these project financings have ranged up to 7 to 8 years, the debt repayment schedule is typically amortized over a longer term.

Given the considerable improvement in the condition of the credit markets over the last six months, likelihood for continued improvement, and recognizing that the terms available (e.g., loan tenor and credit spreads) were more favorable prior to the implosion of the credit markets, the cash flow modeling assumptions reflect continued improvement in credit market conditions.

Support for the 7% debt rate is provided by the fact that a number of utilities have been able to secure debt of equivalent and longer terms at such rates. The DPS notes that available commercial loan rates (for mortgages ranging from $500k to $1.5 M) had rates between 6.5 and 6.75 (for a 7-year term loan) suggesting that 7% is a reasonable proxy.

Equally important is the term of the loan. The financial modeling assumes that projects will be able to amortize loans over 18 (initial modeling of proponent assumptions) to 25-years (DPS modeling of solar projects). While tenors of this length are not currently available, higher quality loans are being amortized over 15-years. Therefore, the cash flow modeling assumes continued improvement in credit market conditions by the time projects need to secure financing.

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[9] Docket 5409, Order of 7/18/90 established a return on equity equal to 12.13 percent for Vermont Marble.

Interconnection Costs

A component of costs for renewable generation included in the modeling are the costs of interconnection. Estimates of total costs from project developers generally included these costs for purposes of the modeling because these costs are generally passed from the utility back to the project developer. A more complete high-level description of these costs is included as Appendix E to this report.

Interconnection requirements may be as simple as a revenue-grade meter and a low cost, secondary voltage disconnect switch or as involved as sophisticated metering packages, real time communications, unique protection schemes, and a primary voltage airbreak switch. These requirements are determined by such things as the size of the proposed renewable generation /distributed generation ("DG") project, the strength of the distribution line to which the DG will interconnect, the topology of the distribution circuit, and the aggregation of additional DG on the circuit. The DG technology itself may also come into play. As a general rule, the complexity of the interconnection requirements will typically increase as size of the resource increases. Larger projects may require reconductoring or other improvements to the local distribution system.

Many aspects of the smaller projects lend themselves to lower interconnection costs. Smaller projects typically require less expensive meters and telemetry. Smaller projects may be able to rely on a pre-existing transformer service at the home or business (rather than requiring a separate Generator Step Up transformer that is larger and more complex). Smaller projects can interconnect at secondary voltages, such as those already serving the home or business. Smaller projects require less expensive disconnection switches or breaker boxes. Also smaller projects may be "fast tracked" through the Rule 5.500 interconnection process. In contrast, the larger projects require generally more complex, expensive systems and require interconnection studies outlined in Rule 5.500.

An important component of the overall interconnection costs, is that associated with the transfer trip scheme. "Islands" of energized conductor can result from distributed generation. Such islanding of energized conductors is a condition that can lead to damaged equipment (from poor quality power), and/or/injury to customers that fall within the island. The transfer trip scheme that is used to address this issue and described in more detail in the Appendix E, will potentially be a major cost factor for interconnection.

As the request of the subgroup Chair, CVPS provided the following guidance on interconnection costs.

> Interconnection costs seems to start around $125,000 for medium sized projects (50 KW, 100 KW, maybe up to 500 KW) and then a variable component for the larger customers due to the cost of the GSU (Transformer) that may add another $40K to $60K.
>
> …for a back yard sized project you are looking at $1000 or less, for the medium size as mentioned above, in the area of $125,000, and for larger projects around $175,000.

At this stage in the process, these figures have not undergone any review or vetting. At least one developer thought that such figures would substantially increase their costs relative to those used in the modeling.

Wheeling Costs and Settlement Costs

Assumptions regarding the wheeling and settlements costs were informed by the technical assumptions from the Settlement and the Wheeling and Interconnection Subgroups. Based on the guidance and direction from those groups the Cost Analysis Subgroup concluded that there was no material incremental costs associated with either wheeling or settlement costs that flowed to the project developers as development costs other than the costs of meter and potentially telemetry associated with these projects.

The Wheeling & Interconnections Subgroup concluded that Act 45 contemplates that each utility should get a prorate share of the power purchased from participating Standard Offer projects, but not require a *pro rata* allocation of the output of each generator. This would mean that wheeling would only be needed for projects whose output was being transmitted out of a utility's system. The Wheeling & Interconnection Subgroup is recommending to treat each Standard Offer generator on a utility's system as a network resource serving that utility's native load, up to a *pro rata* share of the total Standard Offer generation (less any qualifying Standard Offer resources developed by that utility). Since the load already pays for network service, adding the Standard Offer project generation as additional network resources for that utility load would not result in any increase in transmission charges. For any Standard Offer generation beyond the utility's *pro rata* share, the SPEED Facilitator would arrange for the allocation of any wheeling costs under existing wheeling tariffs. The costs would be added to the producer costs and billed directly to the utilities. Thus, wheeling costs would not need to be placed in the standard offer rates.

The SPEED Facilitator estimated that the administrative budget for the first year that most of the projects are operational to be $329,800 and $399,000 if the costs of the first two years are amortized. Assuming a 50-50% split of the administrative costs, the producer's share of the administrative costs is estimated to be $199,500. These costs would have to be allocated and included in the costs to producers, but were estimated to be approximately $119/mo, or $1425 per year. A figure this small is unlikely to have a material impact on modeling results except for the smallest projects. However, the impacts on the smaller projects can be managed by socializing the allocation of the costs associated with the program.

The only other cost item to consider is the cost of meter interrogation through a phone line. However, the costs here will decline with communications capabilities/options and the roll-out smart metering.

Tax Issues

Act 45 requires the setting of the standard offer rate to consider reasonably available tax credits and other incentives provided by federal and state governments and other sources applicable to the category of generation technology. Any profitable business is subject to Federal and Vermont income taxes, with these taxes based on the net income from business activities. Large businesses use many mechanisms to reduce their tax liability and several of those mechanisms will affect the bottom line for a renewable energy project and thus the after tax return on equity that is available. The Subgroup examined the different tax considerations and provided a recommendation for treating each for the purpose of the Standard Offer.

Federal Investment Tax Credit – The Federal Investment Tax Credit ("ITC") for renewable energy production allows for a credit equal to 30 percent of the cost of the installation (less any non-qualifying costs such as transmission interconnection costs) for wind and solar projects (and fuel cells). For combined heat and power (and geothermal and microturbines), the credit is equal to 10 percent of the cost of the installation. One limitation to this non-refundable credit is the need to take the credit against taxable income. For businesses not having sufficient income, the credit value can be taken over several years. In addition, the Federal ITC for renewable energy production was changed by the US Congress in 2008 and 2009 to provide an alternative to the Production Tax Credit (discussed below). *For the cost* *analysis modeling, the full value of the Federal ITC is taken in the first year for all assumed applicable costs (generally 90 to 95% of initial capital costs).*

Vermont Business Solar Tax Credit – The state of Vermont provides a 30 percent income tax credit for photovoltaic installations on business property (equivalent to the federal definition for claiming the Investment Tax Credit). This credit is available to corporations and individuals receiving income from businesses.[10] There are limitations to the Vermont credit that are more restrictive than the Federal ITC for solar installations: (1) the basis of the credit is reduced for projects that receive grant funding and the credit is not available if the project has received funding from the Clean Energy Development Fund; (2) the credit can be carried forward for a maximum of five years and does not have value to taxpayers without a Vermont income tax liability; and (3) the credit is not available if the project has opted to take a US Treasury payment instead of the federal ITC. Two sets of modeling runs are presented in the report. The first or "***initial***" set of runs were developed largely based on inputs from a variety of interests including developers and their representatives. The second or "***DPS***" runs were based on input assumptions developed solely by the Department of Public Service. *The **initial** modeling did not include the Vermont business solar tax credit, however the incentive was included in the **DPS** runs.*

Vermont Investment Tax Credit – Individuals filing income tax returns (this includes individuals receiving pass through income from Partnerships and S-Corps, but not corporate income tax returns) are eligible to take 24 percent of the value of the Federal ITC on energy investments. Given the Business Solar Tax Credit, the Vermont ITC applies for wind and other eligible non-solar energy projects. The credit will only have value for those investors and partners that have a Vermont income tax liability *The **initial** modeling did not include the Vermont investment tax credit. However, the **DPS** model runs included the credit.*

Federal Production Tax Credit – Prior to the expansion of the Federal ITC, the Production Tax Credit provided an incentive for producers of renewable electricity. The credit is for project developers that are selling electricity from renewable sources. The credit is worth between 1.1 and 2.1 cents per kilowatt hour sold to the grid (depending upon source) but is only available when that power is sold at a rate lower than a reference price. That reference price is less than the Standard Offer rates under discussion. As long as the Standard Offer remains at or above this reference price, there will be no benefit. In addition, producers must choose between taking the Production Tax Credit and the Investment Tax Credit. *For the analysis of the Standard Offer, the Subgroup recommends that the Production Tax Credit not be considered.*

US Treasury Grant – While not strictly a tax credit, Congress provided energy project investors a mechanism to receive the value of the Federal ITC as a grant directly from the Treasury. The implication of this option is important in Vermont because receiving the grant eliminates the eligibility to receive the Vermont ITC and the Vermont Business Solar Tax Credit. *For the purposes of the Standard Offer calculation, the Subgroup recommends that analysis be carried out for projects that take advantage of the Federal and Vermont ITC – not the US Treasury Grant program.*

Vermont Clean Energy Development Fund – The fund is not a tax credit, however, for solar installations, a grant from the fund precludes the recipient from benefiting from the Vermont Business Solar Tax Credit. In the past, the Clean Energy Development Fund ("CEDF") has provided $250,000 for solar installations of 50-75 kW. The Small Scale Renewable Energy Incentive is available to smaller projects (<15 kW). The incentive is provided at a set rate of $1.75 per watt for solar projects and $2.50/watt for wind projects. *The **initial** cost analysis modeling did not include the CEDF grant. The **DPS** model runs included it for wind and other technologies, but not for solar.*

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[10] Corporations receive the credit on a single line of their tax return. For individuals with pass through income, the credit is divided into two parts: 24 percent of the credit is wrapped into a list of Investment Tax Credits. The remaining 76 percent is a separate line on the return. For the purpose of this analysis, the Solar Tax Credit can be considered a 30 percent benefit.

Depreciation schedules – The calculation of after tax cash flows for a business includes the use of depreciation as a business expense. The time value of money and rates of investment return influence the choice of the time frame over which to depreciate any assets, including the energy production facilities supported through the Standard Offer. The IRS has rules restricting the rates of depreciation, and recent changes in the law allow for accelerated depreciation which will influence the accounting of energy investments. In general, accelerating depreciation decreases the income tax liability for the current year while increasing the liability for later years. *The cost analysis modeling is assuming an accelerated depreciation for the equipment and standard depreciation for building and other property.*

Income Tax Bracket – Tying all of the income tax issues together is the income tax bracket that the business is subject to. The highest corporate state and federal tax bracket combined is 47.5 percent. The highest personal income bracket combined state and federal is 44.5 percent. Given the significant tax benefits from these projects assuming the highest tax rate is likely to decrease the rate of return for those in lower brackets. Assuming a lower rate will likely increase the rate of return for those in higher tax brackets. *The initial cost analysis modeling used a 35% federal and 8.5% Vermont income tax rate, resulting in a combined state and federal income tax rate of 40.53 percent for all but the Ag methane projects. A 20% federal and 5% state income tax rate was assumed for the largest Ag methane projects and 15% federal and 5% state income tax rate was assumed for the medium and small Ag methane projects.*

Vermont Property Tax - Energy production facilities are subject to the property tax in Vermont communities. Property tax valuation is the basis for the Education Property Tax assessment that is paid to the state. The valuation is also the basis for paying a municipal property tax to the municipality in which the facility is located. Valuing property is the responsibility of a local municipality. The state does provide guidance on valuing property types. *The **initial** cost analysis modeling assumed that property taxes are 1% of the initial capital cost of the project and escalates by 2.5%. In the **DPS** model runs, the Department decreases the property tax to reflect the declining value of the renewable assets as their remaining contract value decreases and the equipment depreciates.*

Grant Funding

The main source of grant funding for renewable energy projects in Vermont is from the Clean Energy Development Fund (CEDF). The Vermont General Assembly established the CEDF through Act 74 (10 V.S.A. § 6523). The Act specifies that the CEDF will be established and funded through proceeds due to the state under the terms of two Memoranda of Understanding (MOU) between the Vermont Department of Public Service (DPS) and Entergy Nuclear VT and Entergy Nuclear Operations, Inc., and by any other monies that may be appropriated to or deposited into the Fund. The CEDF will receive payments from Entergy through 2012. In 2009 the Vermont General Assembly appropriated the $31.5 million in funds from the American Recovery & Reinvestment Act (ARRA) for the State Energy Program (SEP) and the Energy Efficiency Conservation Block Grant (EECBG) into the CEDF to be used for renewable and energy efficiency projects and programs. Due to the ARRA funding for fiscal years 2010 and 2011 the CEDF has budgeted $44 million dollars to be used for renewable and energy efficiency projects and programs. In light of the funding available from the MOU's and ARRA it is reasonable to assume the CEDF is well funded and will continue to offer grants for renewable energy systems for the next few years.

Based on the availability of grants through the CEDF, the DPS set rates assuming a grant is received by a developer for their project. Great Bay Hydro disagrees with this conclusion. Great Bay Hydro has applied for both a CEDF grant and loan for its West Charleston project and has been denied both since the project was deemed to be likely to receive conventional financing. Using this test, any project that is deemed to be financeable should not expect to receive a grant. It is Great Bay Hydro's position that it is not reasonable to set rates for hydroelectric projects assuming that they will receive the CEDF grant unless there is some guarantee that all projects applying for grants will receive them.

The CEDF offers grants to large scale renewable energy systems (greater than 15 kW) up to 50% of the system cost to a maximum of $250,000. In addition the CEDF funds the VT Small Scale Renewable Energy Incentive Program for systems less than 15 kW in size. The current incentive levels under the VT Small Scale Renewable Energy Incentive Program are $1.75/Watt for solar and micro hydro with a maximum if $8750, and for wind the incentive is $2.50/Watt with a maximum of $12,500.

As noted above in the tax discussion, Vermont offers a solar tax credit that is equal to 100% of the Federal Investment Tax Credit. However, if the solar tax credit is used the project is ineligible for a grant from the CEDF. Vermont offers Individuals filing income tax returns (this includes individuals receiving pass through income from Partnerships and S-Corps, but not corporate income tax returns) the ability to take 24% of the value of the Federal Investment Tax Credit on energy investments. Unlike the solar tax credit the Vermont Investment Tax Credit for wind and other eligible renewable energy projects can be used in conjunction with CEDF grants.

Renewable Energy Credits

Pursuant to Subsection 8005(b)(6 all renewable energy credits are conveyed to the retail electricity provider that is purchasing the power from these SPEED resources. The provision applies to all categories of resources except for farm methane resources, as required by statute. As such the modeling of the resources includes an adjustment of $25 per MWh for the REC value of the attributes that flow to the farm methane projects and consequently reduce the price paid by the retail distribution utilities for the purchased energy.

2. Review of Assumptions and Data Integrity

a) Information Received and Process for Review

Participants in the subgroup that represented projects or development interests provided the initial data. Almost all data was supplied during the week of the fifth meeting of the Cost Analysis Subgroup, on August 20, 2009. Review and vetting of the data largely began at the meeting on August 20, 2009. Also at that meeting, the initial modeling runs that incorporated the data into the operational model was presented and later the same day refined and shared with the Subgroup.

Those providing the data were generally instructed to provide costs and performance data that reflected a reasonably efficient operator taking advantage of prevailing best practices, prices, and technology. Given the limited timeframes for review of the data, data providers were strongly encouraged to provide sources and foundation that could support the information being provided. This standard could generally be met through one of two approaches.

b) Resource-Specific Assumptions Used in the Modeling Review

A summary of the detailed runs of each resource is described below. For wind and solar, two sets of modeling runs were relied on, one representing an "***initial***" run relying on data from project developers, among others. The second, was a set of assumptions from the Department, the "***DPS***" model runs.

(1) Wind

Table 3 below summarizes the assumptions and modeling results (i.e., levelized price over the 20-year term of the contract in $/MWh) for the various size wind projects evaluated. As indicated, the assumptions were provided by Green Mountain Power (GMP), the DPS, and Northern Power Systems (Northern Power). Two different project sizes were evaluated: a 1.5 MW wind turbine which is representative of a single commercial scale wind turbine and a 100 kW wind turbine which is consistent with Northern Power's Northwind 100. A less than 15 kW wind turbine wasn't evaluated given that data for such a project weren't readily available.

The critical assumptions for wind projects are the installed capital costs, fixed O&M expenses which include all annual recurring non-capital expenses such as property taxes and insurance and capacity factors. DPS assumed that these projects availed themselves of the Vermont ITC and that the debt term was for the full contract term. In addition, DPS also assumed that the property tax would decline with the decrease in the value of the project. The initial model specification has property taxes increasing by 2.5% per year. DPS also assumed a higher capacity factor for the 100 kW project.

The modeling results suggest that the default price is a reasonable approximation for the 1.5 MW project, recognizing that GMP estimates didn't consider the Vermont ITC. The prices for the 100 kW project range from $171 (DPS assumptions) to $269/MWh (North Wind assumptions). This wide divergence in prices and limited support for the underlying assumptions doesn't allow an assessment regarding the reasonableness of the default price other than if the Board chooses to establish 100 kW Wind as a separate category for its September 15, 2009 determinations, that the default price appropriate for larger wind projects under Act 45, may not represent a reasonable approximation for wind resource below 100 kW..

Table 3

Wind Project Modeling Assumptions and Results

Technology	Wind			
Source of Estimates	GMP	DPS	Northern Power Systems	DPS
Project	1.5 MW		100 KW	
Net Capacity (kW)	1,500	1,500	100	100
Installed Capital Cost ($/kW)*	$3,000	$3,000	$5,850	$5,850
Federal ITC (%)	30%	30%	30%	30%
State ITC (%)		7.2%		7.2%
Grant ($/kW) before tax		$167		$2,500
Fixed O&M ($/kW-year)	$72	$72	$123	$123
Capacity Factor	26.6%	26.6%	23.8%	23.8%
Debt/Equity Ratio**	60/40	60/40	55/45	52/48
Debt Term	18	20	18	20
Contract Term	20	20	20	20
Price ($/MWh)	$126	$111	$269	$171
Default Price per Act 45 ($/MWh)	$123	$123	$123	$123

(2) Farm Methane

Table 4 below summarizes the assumptions and modeling results (i.e., levelized price over the 20-year term of the contract in $/MWh) for the three sizes of farm methane projects evaluated, 300, 65 and 35 kW. The largest project size is representative of a 1,000 cow farm. The assumptions were provided by Vermont Agriculture Department based on existing projects for large farms, and than this data was used to base an estimate of costs for the small farm projects of 65kw and 35kw..

There was considerable detail provided regarding the project assumptions. Specifically, project specific detail was provided regarding revenues from the sales of byproducts, the value of federal and state grants, interconnection costs, and maintenance and staffing expenses. In addition, given that these projects are likely to be owned by farmers, federal and state tax rates that consider their income levels were proposed and used. The aggregate assumptions are outlined below.

The levelized prices resulting from the initial modeling for the three project sizes range from $175 (300 kW project) to $554/MWh (35 kW project). The Departments model results produced a levelized value of $149/MWh which more closely approximates the default price. However, these modeling results suggest that the default price of $120/MWh is unlikely to be a reasonable approximation of price required to enable the development of Farm Methane projects.

Table 4

Farm Methane Project Modeling Assumptions and Results

Technology	Farm Methane			
Source of Estimates	Vermont Ag Department			DPS
Project	Large Farm	Medium Farm	Small Farm	Large Farm
Net Capacity (kW)	300	65	35	300
Installed Capital Cost ($/kW)*	$ 7,628	$ 12,308	$ 15,714	$7,628
Federal ITC (%)	0%	0%	0%	0%
State ITC (%)	0%	0%	0%	0%
Grant ($/kW) before tax	$ 1,928	$ 7,654	$ 10696	$1,928
Fixed O&M ($/kW-year)	$ 767	$ 1,801	$ 2,936	$767
Offsetting Revenue ($)***	$ 95,000	$ 22,500	$ 12,750	$95,000
Capacity Factor	76.5%	76.5%	76.5%	76.5%
Debt/Equity Ratio**	60/40	60/40	70/30	70/30
Debt Term	7	7	7	20
Contract Term	20	20	20	20
Price ($/MWh)	$ 175	$ 345	$ 554	$ 149
Default Price per Act 45 ($/MWh)	$ 120	$ 120	$ 120	$ 120

(3) Biomass /CHP

No project costs estimates were provided by project developers of Biomass/CHP sufficient for modeling project costs so no determination can be made regarding the reasonableness of the default price.

(4) Solar

Table 5 below summarizes the assumptions and modeling results (i.e., levelized price over the 25-year term of the contract in $/MWh) for the various sizes of solar projects evaluated. The assumptions were provided by consultants to REV and the DPS. Three different project sizes were evaluated using the REV assumptions and four using DPS assumptions: a 15 kW, 150 kW, 500 kW and 2.2 MW project, with only the DPS evaluating a 2.2 MW project.

The critical assumptions for solar projects are the installed capital costs, fixed O&M expenses which include all annual recurring non-capital expenses such as property taxes and insurance and the capacity factor. The REV capital cost estimates were based on a survey of members. The DPS estimates were based on project costs contained in the CEDF database. For both the REV and DPS estimates property taxes varied based on the project capital cost. Therefore, the use of a lower capital cost estimate also resulted in a lower fixed O&M estimate. In addition, DPS also assumed that the property tax would decline with the decrease in the value of the project. The initial model specification has property taxes increasing by 2.5% per year. Furthermore, DPS assumed that these projects availed themselves of the Vermont solar ITC (30%) and that the debt term was for the full contract term. Finally, the DPS also assumed higher capacity factors (15% vs. 13%) for the 150 kW and 500 kW projects.

The levelized prices estimated by DPS range from $177/MWh (2.2 MW project) to $368/MWh (15 kW project). The prices estimated using the REV assumptions range from $471 to $557/MWh. The DPS results suggest that if the Board were to further differentiate the resource by size categories of 15 to 150 kW and 150 kW to 500 kW, then the Statutory defaults may reasonably approximate costs, However, the default price may not reasonably approximate costs for projects above 15 kW and below 500 kW Using the REV provided inputs, the default prices would be inadequate across all categories of solar resources eligible for the Standard Offer. These divergent results don't allow an assessment regarding the reasonableness of the default price.

Table 5

Solar Project Modeling Assumptions and Results

Technology	**Solar PV**						
Source of Estimates	**REV Consultant Estimates**			**DPS Estimates**			
Project	**< 15 kW**	**15-150 kW**	**150-500 kW**	**< 15 kW**	**15-150 kW**	**150-500 kW**	**500-2.2 MW**
Net Capacity (kW)	**15**	**150**	**500**	**15**	**150**	**500**	**2.2**
Installed Capital Cost ($/kW)*	**$ 8,140**	**$ 7,170**	**$ 6,850**	**$7,095**	**$6,256**	**$5,964**	**$3,959**
Federal ITC (%)	**30%**	**30%**	**30%**	**30%**	**30%**	**30%**	**30%**
State ITC (%)	**0%**	**0%**	**0%**	**30%**	**30%**	**30%**	**30%**
Grant ($/kW) before tax	**$ -**	**$ -**	**$ -**	**$0**	**$0**	**$0**	**$0**
Fixed O&M ($/kW-year)	**$ 120**	**$ 106**	**$ 102**	**$105**	**$94**	**$89**	**$61**
Capacity Factor	**13%**	**13%**	**13%**	**13%**	**15%**	**15%**	**15%**
Debt/Equity Ratio**	**70/30**	**70/30**	**70/30**	**50/50**	**540/46**	**54/46**	**54/46**
Debt Term	**18**	**18**	**18**	**25**	**25**	**25**	**25**
Contract Term	**25**	**25**	**25**	**25**	**25**	**25**	**25**
Price ($/MWh)	**$ 557**	**$ 493**	**$ 471**	**$368**	**$271**	**$259**	**$177**
Default Price per Act 45 ($/MWh)	**$ 300**	**$ 300**	**$ 300**	**$ 300**	**$ 300**	**$ 300**	**$ 300**

(5) Hydro

Table 6 below summarizes the assumptions and modeling results (i.e., levelized price over the 20-year term of the contract in $/MWh) for a composite hydro project which is a simple average of project cost and operating performance assumptions for three different small hydro projects that are under development in Vermont. The assumptions were provided by BayCorp Holdings for a project that it has under development and two projects under development by Community Hydro.

Credit was taken for a 30% Federal ITC on 90% of the project capital costs. Given the assumed 30-year life of the project, a credit for the project's residual value was taken at the end of the contract term based on the undepreciated (book) value of the project in year 21. Property taxes were assumed to escalate by 2.5% per year and don't reflect that they should decline of the life of the project. Great Bay Hydro notes that the Community Hydro project capital costs don't reflect the investment required to cover interest during construction, spares, or interconnection costs.

The required levelized price for the composite project was $150/MWH under the Great Bay Hydro assumptions and $132/MWh under the DPS assumptions. The key differences in assumptions are that the Department assumes that every project will receive the maximum CEDF grant and be eligible to take the Vermont ITC. Given the experience to date Great Bay Hydro believes that these assumptions are unsupported and therefore its analysis does not include those assumptions. These modeling results suggest that the default price may not represent a reasonable approximation of the price required to enable the development of hydro projects.

Table 6

Hydro Project Modeling Assumptions and Results

Technology	Hydro	Hydro
Source of Estimates	Greate Bay	DPS
Project	Composite Project	Composite Project
Net Capacity (kW)	1278	1,278
Installed Capital Cost ($/kW)	$4,173	$ 4,173
Federal ITC (%)	30%	30%
State ITC (%)		7.2%
Grant ($/kW) before tax	$0	$ 196
Fixed O&M ($/kW-year)	$162	$ 162
Offsetting Revenue ($)		
Capacity Factor	44.9%	44.9%
Debt Term	18	20
Contract Term	30	20
Price ($/MWh)	$150	$ 132

(6) Landfill Methane

Table 7 below summarizes the assumptions and modeling results (i.e., levelized price over the proposed 10-year term of the contract in $/MWh) for a landfill gas project. The assumptions were provided by REV for a small landfill gas project that is under development in Vermont. REV provided information on the capital cost and annual maintenance cost for a project that involved tapping methane from a closed landfill in Randolph, Vermont. Itemized capital and O&M, plant capacity factor, and grant support information is provided by the project developer. The working group has applied this project specific information in the cost model used by the working group. The model uses assumptions about capital structure and debt terms that are not related the actual project example.

Credit was taken for a $200,000 grant, $1,515/kW. The assumed project life was ten years given the available landfill gas reserves. The project developer indicates that the project would be fully depreciated at the end of the ten year life, but the Department of Public Service challenges this.   The DPS's model run produced a price of $129/MWH. In the DPS model they assumed a $250,000 grant, a Federal and State ITC, and a 15 year asset and loan life, and declining property taxes as the contract value decreases.

The project developer is prepared to validate the capital cost and O&M cost, limiting access only to the financing model used for the project. This small project is representative of landfill methane projects that may be developed at a half dozen existing closed landfill sites in Vermont. Vermont has two already developed large landfill methane projects, Coventry and Moretown. Moretown, an active landfill site, may be developed. The working group did not succeed in obtaining information representative of the Moretown site, a site that has been develop in 1.6 MW increments.   Information on Coventry Landfill is available but the working group was unable to complete the analysis of this information for this report.

It appears reasonable to assume that some of the projects that may be developed under the feed-in tariff program are likely to be small projects on the scale of the project for which information is provided here. It is possible that the Moretown landfill may be further developed at some point with a much larger scale generator (i.e., 1.6 MW vs 132 kW scale generator) with a significantly lower kWh cost. REV indicates that the Washington Electric Coop pays approximately 5.5 cents per kWh for output (without renewable energy certificates) from the Coventry landfill, an 4.8 MW plant comprised of three 1.6 MW production units.

The required levelized price for the composite project was $255/MWh which is almost twice the default price of $125/MWh. Given the magnitude of the disparity between the projected required and the default price, limited support for the cost estimates, significant divergence between the rate that would be required based on this analysis and landfill gas prices employed in other feed-in tariff programs, there isn't a sufficient basis to assess whether the default price is a reasonable approximation of the price required to enable the development of landfill gas projects.

Table 7

Landfill Gas Project Modeling Assumptions and Results

Technology	Landfill Gas	Landfill Gas
Source of Estimates	REV Estimates	DPS Estimates
Net Capacity (kW)	132	132
Installed Capital Cost ($/kW)*	$ 4,818	$ 4,818
Federal ITC (%)	0%	30%
State ITC (%)	0%	7.2%
Grant ($/kW) before tax	$ 1,515	$ 1,894
Fixed O&M ($/kW-year)	$ 1,116	$ 591
Capacity Factor	90%	90%
Debt/Equity Ratio**	80/20	65/35
Debt Term	10	15
Contract Term	10	15
Price ($/MWh)	$ 255	$ 129
Default Price per Act 45 ($/MWh)	$ 120	

D. Comparisons of Rates with Other Jurisdictions that have Established Cost-based Feed-in-tariff Rates

As part of the work of the Subgroup, the Chair requested a review of cost-based Feed-in Tariff ("FIT") rates from other jurisdictions that employed a cost based approach. The full comparison is presented in Appendix C and further detail and explanation is available at the Board's website devoted to the Subgroup.[11] This review was provided by the Board's technical advisor, John Dalton, and builds, in large part, from the work of the National Renewable Energy Laboratories (NREL). The review was intended to provide further context for the Board's September 15, 2009 (and later) determinations. In other words, it was intended to provide a touchstone for the review providing some sense of variability in the estimates from other jurisdictions as well as the levels that were ultimately arrived at. Listed in the Appendix are the tables contained in a spreadsheets that contains further context and explanation in footnotes and citations on the Board's web site devoted to the Docket 7523 Cost Analysis Subgroup. Currency conversions were largely based on conversation rates on August 12, 2009.

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[11] http://psb.vermont.gov/docketsandprojects/electric/7523/costanalysis under the "Materials" section of the web page.

The significant variability in the FIT rates is probably explained in large part by four factors (1) differences in capacity size used in these determinations, (2) variability in the exchange rates between the time when rates were determined and the time of the review (August 12, 2009)[12] (3) the offsetting tax advantages available in the US markets that are not generally available at a comparable scale in these other markets, and[13] (4) local factors like available wind and solar resources that may vary widely. Variability in the costs of key components such as recent price declines in the costs of solar PV panels may also be a factor.

E. Adjustment to Generic Price to "Provide Sufficient Incentive for… Rapid Development"

As noted above in the summary Act 45, the legislation provides the Board with the discretion to adjust the rate, although the adjustment must produce only the necessary incentive, not an unreasonable incentive,[14] and the associated return to include factors that provide sufficient incentive for the rapid development of the target renewable resources, but not excessive incentive. As indicated above, there was a wide divergence among Subgroup participants regarding the appropriate cost and performance assumptions for a number of the technologies. Time constraints associated with the work of this Subgroup did not permit adequate time for the Subgroup to resolve these differences. Therefore, the Subgroup was unable to establish a recommendation.

F. Guidance related to "Reasonable Approximation" Determinations

The Subgroup also attempted to guide the Board in its responsibility by providing guidance relative to the "reasonable approximation" determinations. Individual participants suggested views ranging from a low of 10 percent to a high of 20 percent. However, there was also concern with even establishing boundaries and how they could be applied. Other factors (beyond simple application of a range) should be considered by the Board in making such a determination. In the end, there was only consensus that the Board should apply judgment informed by the inherent uncertainties in the underlying data and the policy calls connected to key inputs (e.g., the treatment of Clean Energy Development Fund grants) in the compressed timeframe for developing the cost estimates necessary to make these determinations.

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[12] While rates between the Euro and the Dollar (Dollars/Euro) are only down less than 5% from a year prior (1.49 Dollars/Euro on August 12, 2008 to 1.42 Dollar/Euro on August 12, 2009) they have risen almost 11% over the last 6 months (1.28 Dollars/Euro on February 12, 2009 to 1.42 Dollars/Euro on August 12, 2009) making the cost in the US market more expensive during the latter period. See http://finance.yahoo.com/echarts?s=EURUSD=X#chart2:symbol=eurusd=x;range=2y;indicator=volume;charttype=line;crosshair=on;ohlcvalues=0;logscale=on;source=undefined.

[13] Vermont and the US generally offer more favorable tax incentives than these other jurisdictions which more typically rely primarily on the feed-in tariff to promote the development of these renewable energy resources.

[14] Section 8005(b)(2)(B)(III).

III. Recommendations and Subgroup Conclusions

Agreements within the Subgroup about costs and recommendations to the Board concerning their September 15, 2009 determinations were fairly limited. At a very high level, the group agrees that this Subgroup report accurately frames the issues and provides an appropriate point of departure for the participants in providing supplemental comments that will be filed separately.

A contributing factor to the general lack of agreement was the short space of time to the complexity of the task at hand for the modeling and review of key assumptions. Divergent views centered on the key issues of granularity, solar capital costs, capacity factors for wind and solar, the how to apply the myriad of tax incentives and grants available to the projects. That said, there was general agreement that the models developed through this process provide a generally useful tool for estimating the price necessary to provide the target return on after tax cash flows given technology costs and operating performance. There was also an emerging consensus on many of the more detailed inputs into the modeling.

After review of the results, the group drew the following conclusions:

- Wind -- The modeling results suggest that the default price is a reasonable approximation for the 1.5 MW project, recognizing that GMP estimates didn't consider the Vermont ITC. The prices for the 100 kW project range from $171 (DPS assumptions) to $269/MWh (North Wind assumptions). This wide divergence in prices and limited support for the underlying assumptions doesn't allow an assessment regarding the reasonableness of the default price other than if the Board chooses to establish 100 kW Wind as a separate category for its September 15, 2009 determinations, that the default price appropriate for larger wind projects under Act 45, may not represent a reasonable approximation for wind resource below 100 kW..

- Farm Methane -- The levelized prices for the three project sizes range from $175 (300 kW project) to $554/MWh (35 kW project). These modeling results suggest that the default price of $120/MWh isn't a reasonable approximation of price required to enable the development of Farm Methane projects.

- Biomass -- No project costs estimates were provided by project developers of Biomass/CHP sufficient for modeling project costs so no determination can be made regarding the reasonableness of the default price.

- Solar -- The levelized prices estimated by DPS range from $177/MWh (2.2 MW project) to $368/MWh (15 kW project and below). The prices estimated using the REV assumptions range from $471 to $557/MWh. The DPS results suggest that if the Board were to further differentiate the resource by size categories of 15 to 150 kW and 150 kW to 500 kW, the statutory prices may reasonably approximate costs, However, the default price may not reasonably approximate costs for projects above 15 kW and below 500 kW Using the REV provided inputs, the default prices would be inadequate across all categories of solar resources eligible for the Standard Offer. These divergent results don't allow an assessment regarding the reasonableness of the default price.

- Hydro -- The required levelized price for the composite project was $150/MWH under the Great Bay Corp assumptions and $132/MWh under the DPS assumptions. These modeling results suggest that the default price may not represent a reasonable approximation of the price required to enable the development of hydro projects.

- Landfill Methane -- The required levelized price for the composite project was estimated at $255/MWh which is almost four times the default price of $120/MWh. Given the magnitude of the disparity between the projected required and the default price, limited support for the cost estimates, significant divergence between the rate that would be required based on this analysis and landfill gas prices employed in other feed-in tariff programs, there isn't a sufficient basis to assess whether the default price is a reasonable approximation of the price required to enable the development of landfill gas projects.

The Subgroup agrees that it is preferable for the Board to establish the set interim weighted average residential rate equal to $125/MWh for purposes of establishing clear rate default rather than to simply establish an uncertain price based on "a price equal, at the time of the plant's commissioning, to the average residential rate per kWh charged by all of the state's retail electricity providers weighted in accordance with each such provider's share of the state's electric load."

The Subgroup acknowledged their concerns regarding the considerable uncertainty associated with establishing a cost-based rate determination, especially in the time frame available. Rates set too low risk failure to encourage the "rapid development" of resources consistent with statutory intent. However, if rates are set too high, then Vermont risks sending signals that, in the end, may encourage the deployment of only a single category of resource, to the exclusion of others. The Board is encouraged to address these concerns early in the establishment of the program.

The Subgroup also attempted to provide the Board guidance related to the "reasonable approximation" determinations. There was only consensus that the Board should apply judgment informed by the inherent uncertainties in underlying data and the policy calls connected to key inputs (e.g., the treatment of Clean Energy Development Fund grants) necessary in the compressed timeframe for developing the cost estimates.

As discussed at the last meeting of the subgroup, the group acknowledged that it would be reasonable and appropriate for Board staff and the Board's technical advisor to use the modeling tools and information provided in this report, as supplemented by comments and replies on August 28, 2009 and September 4, 2009 to propose recommendations for and, as appropriate, model any of the detailed decisions of the Public Service Board in setting rates.

Appendices -- Models and Technical Details

Appendix A -- Summary of Model

Pricing Model for Renewable Generation Projects (Anthony Kvedar, GMP)

1. Basic Structure:

The basic structure of the model is to determine a revenue stream over a given contract period that allows a company to recover the costs of building and operating a renewable energy generation project. The model calculates a price to be charged per megawatt hour yielding an annual cash revenue stream. Input into the model are the annual cash out flows. These annual cash expenditures are subtracted from the cash inflows to produce a net annual cash flow number. The annual after tax cash flows calculate an internal rate of return (IRR). The IRR represents the return earned by the equity investor on the generation project. The legislation prescribes the equity investor earn a return of no less than 12.13%, unless adjusted by the Board based on factors defined in the law. Therefore the user of the model can input a price that yields a 12.13% IRR based on the present value of after tax cash flows.

2. Inputs and assumptions:

A number of basic inputs are necessary to correctly represent the annual cash flows.

a. The installation costs to permit, build, and prepare the facility to be energized.

b. The model also provides for a working capital allowance, a debt reserve, and a maintenance reserve. The reserves are returned to the investor at the end of the contract period.

c. The model also allows for the investor to receive grants. These grants are assumed to be taxable income and the model recognizes the tax effects of the grants before including them in the after tax cash flows.

d. The model provides for the equity investor to be an income tax paying entity. If the investor is a tax paying entity it is necessary to enter the applicable state and federal income tax rates.

e. The model provides for a portion of the investment to be funded by a loan. It is necessary to enter the capital structure of the investment as well as the interest rate on the loan, and the life of the loan.

f. The model will both utilize both state and federal Investment Tax Credits (ITC) if available to the investor. The state tax credit is reduced by the federal tax rate. The state ITC reduces the state income tax liability therefore reducing the federal income tax deduction provided by the state income tax.

g. The megawatt out put of the generating facility is calculated by the name plate capacity of the plant multiplied by a capacity factor.

3. Calculations:

The model will calculate the inputs into annual cash flows over the life of the asset.

a. The initial investment and reserves, grants and allowances will impact cash flows in the year prior to the first year of operation.

b. Starting the first year of the generating plant's operation a full year of generating out put is assumed. This calculates a revenue stream.

c. Subtracted from the revenue stream are out of pocket operation and maintenance costs.

d. The model calculates annual accelerated income tax depreciation for both state and federal income taxes. It is assumed the investor can utilize these income benefits as the model assumes any negative income tax expense is a positive cash flow to the equity investor.

e. The federal ITC is assumed to be utilized in full in the first year of operations. The state ITC when utilized is earned over the first five years of operation. Therefore the model treats them as positive cash flow to the equity investor.

f. The model calculates the loan repayment to the lender in equal annual payments (e.g., similar to a mortgage) over the life of the loan. The payment is calculated as a cash out flow to the equity investor.

4. Model validity:

The calculation from model is tested by comparing it to a calculation from a cost of service model. The cost of service model utilizes a calculation method that is used in utility rate cases. The methodology provides the investor an allowed return on the unrecovered cash invested in the project. The model is constructed using end of year balances instead of a mid year balances. This makes the calculation more consistent with cash flow model. The cost of service model assumes the investor recovers their investment over the life of the asset using straight line depreciation. The accelerated tax depreciation benefit and the investment tax credit reduce the balance that earns a return for the investor.

The annual cost of service is present valued over the contract life and an annuity factor is applied. The answer is a levelized price. The price calculated using the cash flow model should be very similar to the cost of service model providing a double check. The factor that will cause a difference in the two calculations is the assumed loan life. The greater the number of years the loan life differs from the contract life, the greater the difference in the two calculated prices.

The model has also been available for review and comment on Public Service Board's web site since August 4, 2009. During that period it has undergone numerous edits and revisions based on input from modelers and others participating in the process. The model has also been reviewed against results of other generally simpler models.

Appendix B – Summary of Assumptions

As part of the process, the Subgroup Chair, J. Riley Allen, requested those providing input assumptions to provide a summary of their recommendations for the inputs along with the foundation (sources and rationale) for the inputs provided. That input and explanation is provided below with only minor editing for clarity and flow.

Cost Analysis Assumptions – Hydroelectric – (Anthony Callendrello, Great Bay Hydro)

Technology

In developing the costs for new hydroelectric capacity in Vermont, it has been assumed that the hydroelectric capacity additions that will occur in the near term will all be the addition of power generation equipment to existing dams. This assumption is supported by the fact that there are a number of such projects currently being developed in Vermont. Given the significant regulatory hurdles associated with the construction of a new dam and impoundment; that option is considered to be unlikely for the foreseeable future and the costs for such a project would be considerably higher than assumed.

Cost Basis

Hydroelectric costs were developed based on information from three hydroelectric projects currently under development in Vermont. One is a 675kw project being developed by Great Bay Hydro in Charleston, Vermont. The other two are being developed by Community Hydro; a 960kw unit in Townshend, Vermont and a 2,200kw unit in Jamaica, Vermont. The sizes of three projects were averaged with the result being a nominal 1,278kw unit. All cost and capacity information was also averaged. It is unlikely, given the cost of licensing and development, that new hydroelectric projects with capacities of less than 500kw will be proposed.

Installed Capital Cost

For the Charleston project, construction and equipment costs were developed based on an engineering estimate using standard takeoff pricing as well as vendor quotes for major equipment. The development costs were based on actual costs incurred and projected through the start of construction. For the Community Hydro projects, capital costs were estimated as part of the preliminary permit application and have been further refined as additional vendor information has been received. It should be noted that the capital costs for the Community Hydro projects do not include the cost of interconnection. Based on standard development costing practice, interest during construction has been calculated assuming 70% debt, a 7.00% interest and a 12 month construction period.

Operating Costs

For the Charleston project, operating costs were estimated based on Great Bay Hydro's experience operating the 4.0mw Newport 1, 2, 3 hydroelectric project in Newport, Vermont. For the Community Hydro projects, the operating costs were estimated based on prior operating experience.

It should be noted that property taxes were assumed to be 1.00% of the installed cost of the equipment. Further, no wheeling costs were assumed based on the assumption that the projects would not be responsible for those costs. Given that wheeling reservations must be made in 1mw increments and the open access tariff is approximately $1,680/mw-mo, that if not otherwise paid for, would add approximately $20,000 per year in operating costs to any project with a capacity of 1mw or less.

Capacity Factor

The annual generation for each of the projects has been estimated based on historic flows and the projected operating characteristics of the generating units. The average capacity factor for the three projects was used. Project availability is assumed to be 98% based on the history of operating projects.

Federal Tax Credits

For the development of the standard offer prices it is assumed that hydroelectric generation will receive the 30% investment tax credit. While the American Recovery and Reinvestment Tax Act of 2009 did extend the investment tax credit to many types of renewable energy facilities, in order to receive that tax credit the facility must be a qualified facility as described in certain sections of 26 USC § 45. Under 26 USC § 45 (c)(8), qualified hydropower production falls into two general categories; incremental hydropower production at an existing hydroelectric dam, and the addition of generation at an existing non-hydroelectric dam. The latter is further restricted to require that the facility be licensed by FERC, that the dam did not produce hydroelectric power before a certain date and that there be no enlargement of the diversion structure, construction or enlargement of a bypass channel or the impoundment or withholding of any additional water. It is uncertain whether the facilities that are likely to be constructed in the near term will qualify for the investment tax credit.

Photovoltaic (MCG on behalf of Renewable Energy Vermont)

Meister Consultants Group, Inc. (MCG) surveyed Renewable Energy Vermont (REV) member companies [15]on behalf of REV in order to determine Vermont-specific photovoltaic installed costs, and other input data, for use in determining the reasonableness of the proposed feed-in tariff rates.

Installed costs

MCG collected installed cost data for several different PV system sizes based on the capacity thresholds proposed by REV in its July 2, 2009 Comments on the Issues List. This data included real property, equipment, interconnection equipment, permitting, interconnection studies, site preparation, installation, and commissioning costs. MCG then compared data provided by Vermont installers to develop generic installed costs that reflect installer inputs but maintain confidentiality.

The resulting recommended installed costs, contained in the table below, were then benchmarked against installed cost data gathered from other sources. These included: the database of systems funded in 2007-2009 by the Massachusetts Technology Collaborative (MTC),[16] the installed cost assumptions used by the Gainesville Regional Utility to set their existing solar photovoltaic feed-in tariff in 2009, and the data reported in the California Energy Commission Cost of Generation (COG) Update[17] (which was released a few days ago). As can be seen from the table below, the generic costs for Vermont are lower than in the three benchmark jurisdictions for all size categories.[18]

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[15] Available at http://psb.vermont.gov/sites/psb/files/docket/7523/July2Filings/REV%2007-02-09%20comments.pdf.

[16] Massachusetts Technology Collaborative (2009). Commonwealth Solar – Information on installers and costs – updated 05/04/09. Available online at: http://www.masstech.org/SOLAR/CSInstallerCostLocationData.xls.

[17] KEMA, Inc. 2009. Renewable Energy Cost of Generation Update, PIER Interim Project Report. Prepared for the California Energy Commission. CEC-500-2009-084.

The DPS collected installed cost data from the database of systems funded in 2007-2009 by the Massachusetts Technology Collaborative (MTC), and July 2009 grant proposals to the CEDF. The data was assemble to include only the average of the top 50% price performers of MTC data of systems install in 2009.

Installed cost ($/Watt dc)	< 15 kW	15-150 kW	150-500 kW	> 500 kW
Initial Proposed Costs	$ 8.14	$ 7.17	$ 6.85	$ 6.40
MTC (2007-2009) (704 systems)	$ 8.68	$ 7.83	$ 7.03	$ 7.14
California COG Update 2009 (15,000 systems)	$ 8.18	$ 7.86	$ 7.86	$ 7.34
Gainesville Regional Utility Feed-in Tariff	$ 7.50	$ 7.50	$ 7.50	$ 7.50
DPS Proposed Costs	$7.09	$6.25	$5.96	$3.96

It remains unclear which size category will be picked as "representative." The choice of whether to set the rate conservatively or aggressively, or whether to differentiate by size will ultimately reflect state policy objectives. Ontario, for example, used a conservative rate for its 2006 PV standard offer that supported only the largest system sizes to be developed. Partially as a result of the conservative pricing, many of the projects that "got in line" were never developed. Germany, by comparison, has successfully driven residential PV market growth because of its targeted solar tariffs for small systems, and Ontario appears poised to do the same with its 2009 feed-in tariffs. As discussed in prior comments, it is REV's position that the standard offer should be differentiated by size. If the standard offer is not differentiated by size, it is recommended that the price be set at least at the 150-500 kW level proposed in the attached so that large building owners will have an opportunity to participate in the program, rather than simply large land owners.

Annual Expenses

The primary annual expense categories are operations and maintenance (O&M), insurance, and property tax. There was general agreement among PV stakeholders that a defensible O&M figure for a large-scale PV system is $6/kW/year, and a defensible figure for insurance costs is $25,000/MW/year. It is difficult to find empirical benchmarks for O&M and insurance cost data, and so MCG relied on stakeholder consensus.

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[18] The exception for this is < 15 kW in Gainesville, where the same installed cost was assumed for all system sizes.

Stakeholders commented that the Board should consult with the tax authorities on property tax calculations. It is thought that property tax is calculated as:

Annual revenue – annual costs / capitalization rate

If this is the case, then property tax depends on revenue, which would depend in turn on the feed-in tariff level, which is yet to be determined. However, the Department offered a different view, arguing that the value of a project decreases over time as its physical life and contract life are used up. Their property tax calculation was calculated as:

(NPV revenue – NPV costs) * Tax rate

Inverter costs

A significant expense for PV generators is the replacement of the inverter. For cash flow purposes, REV recommends that the model assume an inverter replacement in Year 12. Inverter costs decline by 10% with every doubling of demand,[19] and the US Department of Energy's goal for inverter costs is \$0.25-\$0.30/ watt_{dc} by 2020. REV stakeholders believe that an inverter replacement cost of \$0.27/watt_{dc} would be reasonable.

Other inputs

With regard to other inputs, REV stakeholders believe that the PV model should assume:

- 25-year operating life
- 13% capacity factor (with all losses taken into account)
- 100% equity financing, given the current financial climate and the lack of available debt[20]

Farm –Based Methane: (Dan Scruton, Vermont Agency of Agriculture, Food and Markets)

An anaerobic digester typically is a vessel that holds manure (to which substrates such as whey can be added) heated to about 100°F for 20 days. Methane is released from the slurry through a biological process that simultaneously reduces the odor in the manure and makes the plant nutrients more soluble. Burning the methane through an engine-generator set (genset) provides heat and power as well as reduces greenhouse gas emissions. Most of the heat is used to heat the manure but some is available for on-farm use. The power is sold to the local utility. Digestion also improves neighbor relations due to the reduced odor in the effluent when spread on the fields to help in crop production.

Vermont is one of the most dairy intensive states in the country and with that distinction, comes a large number of dairy farms. There are currently over 1000 dairy farms in Vermont averaging about 125 cows each. Anaerobic digestion of the manure is a technology that has been in use in the US for over 30 years but has not gained traction needed for widespread adoption. The Public Service Department (DPS) in partnership with the Vermont Agency of Agriculture, Food and Markets (VAAFM) launched a program to investigate the hurdles to the widespread adoption of the technology with the Vermont Methane Pilot Program (VMPP) in 1999. One of the main issues identified in that report is the marginal economics of utilizing the technology. The CVPS Cow Power program combined with a study, funded by the VMPP, that showed the use of solids separated from digested manure was a suitable bedding material for cattle has spurred some construction of systems. The 25x'25 goals estimated that about half of the cows in the state are managed in a fashion that would be conducive for anaerobic digestion and that would yield 15 megawatts of capacity adding energy crops and substrates and it is estimated that 45 megawatts of generating capacity could be achieved. We have about 50 farms with over 500 milk cows; about 150 between 200 and 500; and the remaining farms are less than 200 cows each. For that reason three farm size systems are detailed for this report. Large farms for the purpose of this data would be farms with 500 or more cows or systems with a capacity of over 100 kW. Medium farms would be 200 to 500 cows or a system capacity between 50 and 100 kW. Small farms would be systems with less than 50 kW of output.

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[19] Navigant Consulting Inc. (2006). A review of PV inverter technology cost and performance projections. Golden, CO: National Renewable Energy Laboratory. NREL/SR-620-38771.

[20] Schwwabe, P., Cory, K., & Newcomb, J. (2009). Renewable energy project financing: Impacts of the financial crisis and Federal legislation. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A2-44930.

Major Cost Drivers:

Anaerobic digester systems are capital intensive installations both for start-up and for on-going operation. The systems include a large tank that can hold about 20 days worth of manure plus a gas space. The tanks need to be both liquid and gas tight. The gensets require frequent oil changes and maintenance. It is expected that the engine will be totally rebuilt or replace every five years with current technologies. One of the farms that stated making power in 2005 has already replaced their engine. The equipment used to separate the manure solids from the digested slurry is also high maintenance where the parts that put the pressure onto the manure to remove the liquid involve parts that wear. The digester tank itself will need occasional clean-outs where the system is drained and solids that have settled to the bottom are removed. The electrical components are susceptible to corrosion from the manure gasses that escape into the generator building. The handling of the manure and the maintenance is also labor intensive requiring a significant daily labor input.

Input Assumptions:

The input assumptions for the large farms are largely based on actual data being collected by Glenn Rogers, Regional Farm Management Specialist, UVM Extension. Glenn was hired as a joint project between CVPS and VAAFM to determine the economics of existing digesters. The final report will be out this fall but Glenn shared some of his preliminary data collected from the farms with us. The size selected for large farms is the actual average of the four farms in Glenn's study. The capital cost and interconnect costs are also the average of the four farms standardized to 2009 dollars. Maintenance costs are based on a formula used the Farm Credit Corporation for budgeting purposes of farm equipment in general. Their suggestion is that you need to budget 5% of the cost of buildings and 12.5% to 15% of the cost of machinery annually. For Large farms the low end of the range was used. The labor input is an educated guess on what the labor is going to be over a 20 year period, recognizing that the labor for the first few years of operation is likely less than the last few years looking out over a 20 year period. The labor rate is an estimate of the average cost of the various levels of expertise needed for the different jobs that need to be done and includes any overhead costs for the labor. Other income was a combination of hot water displacement in the milk house , sawdust replacement. A value of $5,000 was used for heat replacement. The real number on the four farms varied from $0 to $10,000 in value with some using the heat for hot water in the milk house; one doing some spacing heating in a garage attached to the digester control building and some not be able to use any beyond heating the digester builder. Where the digester building would not be heated if they did not have the digester I did not count that and settled on $5,000.00 Solids sales were a combination of bedding replacement on-farm and sales to other farmers and landscapers. The actual average was $110,000 in solids value and $20,000 was subtracted from that as a value for the undigested manure.

The small and medium farm assumptions are estimate based on expected costs from a variety of quotes for systems in the various size ranges. The maintenance percentage for the mechanical equipment was raised to the higher end of the Farm Credit range being 14% for medium systems and 15% for small systems assuming that many of the maintenance items were the same on small and large systems but a small system had less total cost to spread them out over. The labor was reduced some but will not be significantly reduced as most of the jobs that need to be done are the same just on a smaller scale.

All systems are assuming a seven year loan term at 7%. In talking with lending institutions, such as Vermont Economic Development Authority a seven year loan is the maximum they will consider on this type of equipment.

Small Farm Input Assumptions Per by Dan Scruton

Model Input	Assumption
Technology	Small farms
Net Capacity (kW)	35 kW
Economic Life (years)	20
Capital Cost ($/kW)	$15,714
Salvage Value ($)	none
Annual Fixed O&M Costs ($/kW-year)	$3,314.52
Variable O&M Costs ($/MWh)	
Non-recurring Maintenance Expense ($)	
Fuel Costs ($/MMBtu)	
Heat Rate (MWh/MMBtu)	
Offsetting Revenue	12750
Net Capacity Factor (%)	77%
Investment Tax Credit (%)	0%
Applicable Capital Cost for ITC (%)	0
Other Grants or Applicable Programs	374350
Tax Depreciation (% of Capital Cost)	20 year straight line 67% of D31
Tax Depreciation (% of Capital Cost)	7 year straight line 33% of D31
Book Depreciation	
Project Ownership Type	enterprise of farm
Federal Income Tax Rate (%)	0.2
State Income Tax Rate (%)	5

Capital Cost Breakout Total $ (Complete if available and appropriate)*	
Model Input	Assumption (2009$)
Total cost	$ 500,000

Sales Tax	$ -
Electric Interconnection	$ 50,000
Spare Parts Inventory	
Financial Fees	
Regulatory Permitting Costs	
Other Development Expenses	
Owner & Lender Engineers during Construction	
Interest during Construction	
Insurance during Construction	
Developer Fee	
Project Contingency	
Total $	$ 550,000

Annual Fixed O&M Expense Total $
(Complete if available and appropriate)

Model Input	
Maintenance Cost	$ 41,500
Staffing & Operating Cost	$ 61,250
Property Tax (% of Applicable Capital Cost)	minor
Insurance	included in D50
Wheeling Charges (will be added if appropriate)	NA
FERC Charges	
ISO-NE Charges	
Total	$ 102,750

Capacity Factor
(Complete if available and appropriate)

Model Input	Assumption
Gross Project Capacity Factor	85%
Project Availability Factor	90.00%
Loss Factor	
Net Capacity Factor	77%

Medium Farm – Input Recommendations per Dan Scruton

Model Input	Assumption
Technology	Medium farms
Net Capacity (kW)	65
Economic Life (years)	20
Capital Cost ($/kW)	$12,308
Salvage Value ($)	none
Annual Fixed O&M Costs ($/kW-year)	$2,053.40
Variable O&M Costs ($/MWh)	
Non-recurring Maintenance Expense ($)	
Fuel Costs ($/MMBtu)	
Heat Rate (MWh/MMBtu)	
Offsetting Revenue	22500
Net Capacity Factor (%)	77%
Investment Tax Credit (%)	0%
Applicable Capital Cost for ITC (%)	0
Other Grants or Applicable Programs	497500
Tax Depreciation (% of Capital Cost)	20 year straight line 67% of D31
Tax Depreciation (% of Capital Cost)	7 year straight line 33% of D31
Book Depreciation	
Project Ownership Type	enterprise of farm
Federal Income Tax Rate (%)	15
State Income Tax Rate (%)	5

Capital Cost Breakout Total $	
(Complete if available and appropriate)*	
Model Input	Assumption (2009$)
Total cost	$ 700,000
Sales Tax	$ -
Electric Interconnection	$ 100,000
Spare Parts Inventory	
Financial Fees	
Regulatory Permitting Costs	
Other Development Expenses	
Owner & Lender Engineers during Construction	

Interest during Construction	
Insurance during Construction	
Developer Fee	
Project Contingency	
Total $	**$ 800,000**

Annual Fixed O&M Expense Total $	
(Complete if available and appropriate)	
Model Input	
Maintenance Cost	**$ 55,790**
Staffing & Operating Cost	**$ 61,250**
Property Tax (% of Applicable Capital Cost)	**minor**
Insurance	**included in D50**
Wheeling Charges (will be added if appropriate)	**NA**
FERC Charges	
ISO-NE Charges	
Total	**$ 117,040**
Capacity Factor	
(Complete if available and appropriate)	
Model Input	**Assumption**
Gross Project Capacity Factor	**85%**
Project Availability Factor	**90.00%**
Loss Factor	
Net Capacity Factor	**77%**

Large Farm – Input Assumptions per Dan Scruton

Summary Assumptions	
Model Input	**Assumption**
Technology	**Large Farms**
Net Capacity (kW)	**300**
Economic Life (years)	**20**
Capital Cost ($/kW)	**$7,628**
Salvage Value ($)	**none**
Annual Fixed O&M Costs ($/kW-year)	**230248**

Variable O&M Costs ($/MWh)	
Non-recurring Maintenance Expense ($)	
Fuel Costs ($/MMBtu)	
Heat Rate (MWh/MMBtu)	
Offsetting Revenue	**95000**
Net Capacity Factor (%)	**81%**
Investment Tax Credit (%)	**0%**
Applicable Capital Cost for ITC (%)	**0**
Other Grants or Applicable Programs	**578313**
Tax Depreciation (% of Capital Cost)	**20 year straight line 67% of D31**
Tax Depreciation (% of Capital Cost)	**7 year straight line 33% of D31**
Book Depreciation	
Project Ownership Type	**enterprise of farm**
Federal Income Tax Rate (%)	**20**
State Income Tax Rate (%)	**5**

Capital Cost Breakout Total $	
(Complete if available and appropriate)*	
Model Input	**Assumption (2009$)**
Total cost	**$ 2,106,324**
Sales Tax	**$ -**
Electric Interconnection	**$ 182,142**
Spare Parts Inventory	
Financial Fees	
Regulatory Permitting Costs	
Other Development Expenses	
Owner & Lender Engineers during Construction	
Interest during Construction	
Insurance during Construction	
Developer Fee	
Project Contingency	
Total $	**$ 2,288,466**

Annual Fixed O&M Expense Total $	
(Complete if available and appropriate)	
Model Input	
Maintenance Cost	**$**

	157,448
Staffing & Operating Cost	**$ 72,800**
Property Tax (% of Applicable Capital Cost)	**minor**
Insurance	**included in D50**
Wheeling Charges (will be added if appropriate)	**NA**
FERC Charges	
ISO-NE Charges	
Total	**$ 230,248**
Capacity Factor	
(Complete if available and appropriate)	
Model Input	**Assumption**
Gross Project Capacity Factor	**85%**
Project Availability Factor	**90.00%**
Loss Factor	
Net Capacity Factor	**77%**

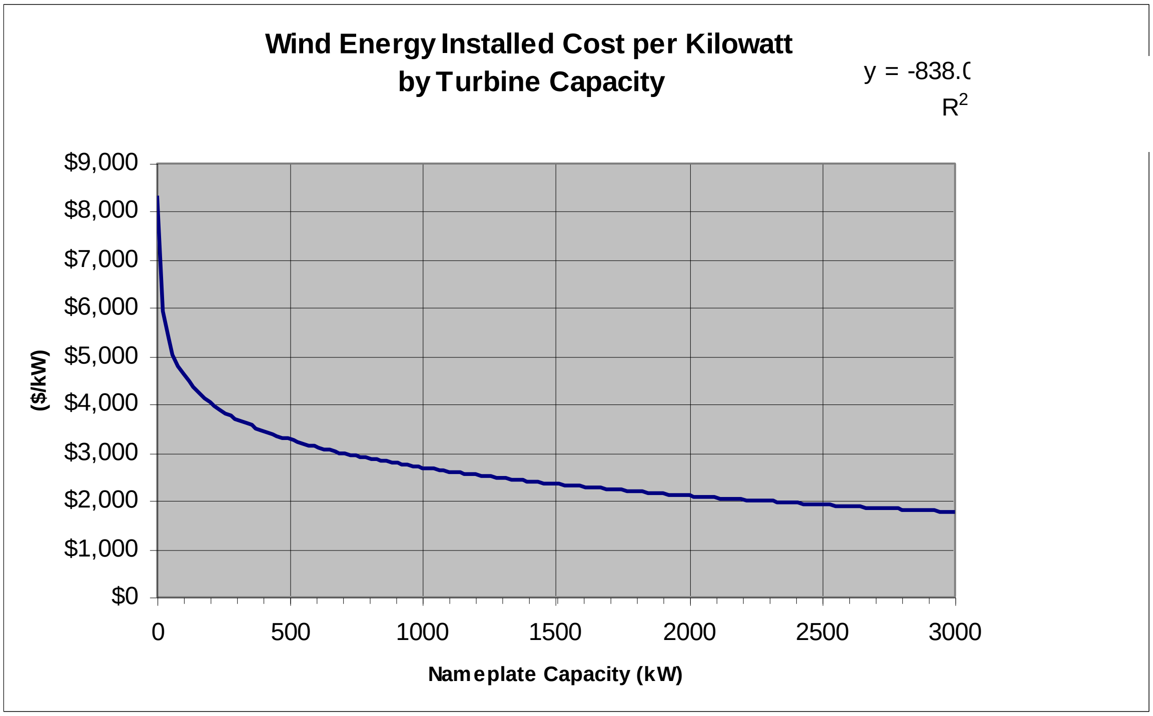
Wind 100 kW – (Northern Power)

The Northwind 100 is a 100kW capacity turbine manufactured by Northern Power Systems in Vermont. Its permanent magnet, direct drive technology (as opposed to gearbox based designs) is unique to the community wind industry and provides the most efficient, quietest turbine on the market today. The Northwind 100 is, as Governor Douglas described the turbine on April 14th at an event at Northern Power Systems in Barre, a “Vermont-scale” turbine - it has a 37m (121 feet) hub height (about the height of a typical municipal water tower), as opposed to the much higher 80m (262 feet) or even 100m (328 feet) hub heights for utility scale turbines.

Wind Technology

Small Wind Tier, 16-100kW

The cost of wind energy varies significantly in proportion to the nameplate capacity of the turbine. The swept area of the turbine blades determines the force into the machine and governs the potential power rating of the machine. The area of the blades is a function of the square of the radius (roughly an individual blade length). A machine with a 21m rotor can make 100kW of power, while an 80m rotor (almost four times the rotor size) can make 1,500kW of power (fifteen times the power). In short, the cost of wind energy decreases in a non-linear fashion as nameplate capacity increases (chart below).



As a result, the 15kW-2200kW band created for wind in Act 45 is too wide and does not represent a reasonable approximation of the costs and returns of all the capacities within that band. The more efficient incentive for wind projects is to create sub-capacity "bands" or "tiers" that more accurately reflect the slope of the cost curve at those nameplate capacity sizes. In the course of working with the Cost Analysis subgroup, Northern Power submitted a study of publicly installed costs on a wide variety of turbine sizes (forming the cost curve above) and proposed three tiers (in addition to the 0-15kW named by the legislature) with the least variance within each tier: 16kW-100kW; 101kW-500kW; and 500kW-2200kW. That study can be found in PDF form at http://psb.vermont.gov/docketsandprojects/electric/7523/costanalysis and is attached to this Appendix.

Cost Assumptions

The major factors in determining the final cost of energy in a wind project include: 1) the assumed wind speed at hub height and expected Capacity Factor of the turbine being installed, 2) the development costs associated with any particular site, 3) the type of entity (taxable or public/non-profit) doing the project, 4) permitting, 5) interconnection, and 6) ongoing O&M costs.

Capacity Factor

Capacity Factor is a critical component in determining cost/kWh on a wind project. Importantly, the wind resource for any project varies by BOTH the site location and height of the turbine. By definition, at any given site a taller tower is going to have higher wind speeds, greater capacity and larger production than a shorter tower. This is particularly true in Vermont where the topography creates increased wind shear and the highest wind speeds are atop the ridgelines.

In order to accurately define an assumed capacity factor for "well-sited" projects in the State, Northern Power used AWS Truewinds wind data (50m hub height, originally commissioned by the Massachusetts Technology Collaborative state agency in Massachusetts (http://www.masstech.org/rebates/Community_Wind/wind_maps.htm) to create a mean wind speed for each of the 317 zip codes in Vermont. We then sheared that wind speed up to the 80m hub height (using a shear factor of .147) representative of a GE1.5MW turbine and fit that data to the power curve of the GE1.5 turbine. We determined the capacity factor for the top quintile of zip codes of well-sited installations to be approximately 26% at 80m. Given the NW100 is at a 37m hub height, the equivalent average annual mean wind speed is approximately 5.6m/s and the resulting capacity factor would be 20-21%.

Publicly available GIS data of actual Vermont sites (www.vcgi.org) supports the notion of "well-sited" being below 6.0m/s for a 100kW turbine. Data adjusted to 37m hub height wind speed (the height of the NW100) show:

- of 398 schools in the state, only 2 have greater than 6.0m/s wind speed;
- of 1517 government and public buildings, only 8 have greater than 6.0m/s wind;
- of 291 fire stations, only 1 has greater than 6.0m/s wind speed.

As a result of both these studies, we believe the realistic capacity factor for the Northwind 100 in Vermont is 20-21%. The statewide data from Vermont indicates attaining higher capacity factors (regardless of tower height) will require accessing ridgeline locations, with significantly higher permitting, development and interconnect costs than assumed in this model. "Well-sited" wind projects in Vermont can also be defined as being closer to the communities they serve, and more acceptable in size and location to community members. If schools and businesses are able to site turbines at or near their facilities under the standard offer process, wind technology adoption rates will increase, which is a goal under Act 45.

Installed Costs

Because each NW100 project varies, total installed costs can fall anywhere within a wide spectrum from an open farm field install on well drained soil in the Midwest (low cost) to a wind/diesel village on the tundra in Alaska (very high cost). At this point in time, there have been no completed installations in Vermont, and no NW100 has applied for and completed a Section 248j permitting process. In addition, as a disclaimer it must be noted that Northern Power is a manufacturer of turbines, not a project developer. Although we sell to both end users and developers, we are not in the business of modeling internal development costs.

In order to arrive at an accurate and fair estimate of costs, we took the publicly disclosed install costs of two actual school projects completed in the last 9 months at McGlynn Elementary School in Medford, MA (http://www.icleiusa.org/action-center/learn-from-others/Medford%20Energy%20Independence%20Project.pdf) and Appalachian State University in Boone, NC (http://www.news.appstate.edu/2009/06/24/wind-turbine-on-campus/). We took the average of the total installed costs of these projects ($585,000) and netted out the costs of our turbine and an estimate on interconnection costs to determine an average level of overall development costs. These costs are for turbine installations only, and do not include kiosk or educational components or incremental improvements to existing infrastructure not related to the wind turbine.

Tax Status/Grant Assumptions

The cost/kWh for a generic Northwind 100 project in Vermont as currently put forth by the PSB assumes a taxable entity eligible to claim the 30% Federal Investment Tax Credit. Costs would be significantly higher for a public entity unable to claim this credit. In order to produce similar cost plus returns for a non-profit will require a higher rate under the standard offer program.

There is no grant funding assumed from the Vermont Clean Energy Development Grant Program (CEDF). Given the uncertain nature of a competitive grant program, the infrequent semi-annual funding cycle, and its limited funding this was not assumed to be a reliable source for costing a project.

As regards both these items, Northern Power would suggest taxable entities be required to choose between the CEDF or the Standard Contract – but not both (California has a similar provision in their Self-Generation Incentive Program). Although not under the jurisdiction of the PSB, we would suggest one possible solution to the issue of non-taxable entities having a significantly higher cost basis is to allow them access to the CEDF. However, since CEDF funds will also be used for the purposes of reimbursing the Vermont solar tax credit, CEDF funding for public entities will be dramatically and negatively impaired.

Permitting Costs

As indicated above, there is no itemized cost entry for the permitting process for the Northwind 100. Our development partners in Vermont indicate permitting costs for a net-metered project are around $10,000 – a level we are comfortable is captured by the out-of-state projects cited in our assumptions. But because we have yet to go through the more detailed permitting process for a Standard Offer project, we really do not have any reliable estimate of those costs. As we get a better handle on these costs in the future, we would reserve the right to adjust them upward, perhaps as early as the January 15, 2010 price setting.

Wind 100 kW – Per Northern Power

Input	**Factor into the model? (1)**	**Wind (16-100 kW)**
Production Factors		
Capacity factor	Yes	20-25%
Representative capacity (kW)	Yes	100
Capital Costs		
Real property: land & buildings	Yes	

Equipment	Yes	$ 330,000
Interconnection equipment	yes	$ 10,000
Development Costs		
Permitting	yes	
Interconnection studies	yes	
Site preparation	yes	
Other development costs	yes	$ 245,000
Operating Costs		
land lease		$ 1,000
Maintenance	Yes	$ 5,400
Property tax	Yes	
Fuel costs (biomass only)	Yes	
Insurance	Yes	$ 1,000
ISO charges	Yes	
FERC charges (for hydro)	Yes	
Wheeling charges		
Cost of Capital		
Capital structure - debt %	Yes	0%
Capital structure - equity %	Yes	100%
Cost of debt %	Yes	7.5%
Return on equity % OR	Yes	12.21
Total cost of capital %	Yes	
Discounting		
Discount rate		

Contract Length		
Standard offer duration	Yes	20
Salvage		
Salvage value	No	0
Tax Credits		
Eligibility for Federal ITC	Yes/No	Y
Eligibility for Federal PTC	Yes/No	Y
Eligibility for VT Solar tax credit		
Grants		
Expected grant amount or %	No	0

Appendix C – Detailed Summary of Rates from Other Jurisdictions

As part of the work of the Subgroup, the Chair requested a review of cost-based Feed-in Tariff ("FIT") rates from other jurisdictions. This review was provided by the Board's technical advisor John Dalton and builds, in large part, from the work of the National Renewable Energy Laboratories (NREL). The review was intended to provide further context for the Board's September 15, 2009 (and later) determinations. In other words, it was intended to provide a touchtone for the review providing some sense of variability in the estimates from other jurisdictions as well as the levels that were ultimately arrived at. Listed below are the tables contained in a spreadsheets that contains further context and explanation in footnotes and citations on the Board's web site devoted to the Docket 7523 Cost Analysis Subgroup.[21] Currency conversions were largely based on conversation rates on August 12, 2009.

Explanation for the significant variability in the FIT rates is probably explained in large part by four factors (1) differences in capacity size used in these determinations, (2) variability in the exchange rates between the time when rates were determined and the time of the review (August 12, 2009)[22] (3) the offsetting tax advantages available in the US markets that are not generally available at a comparable scale in these other markets, and (4) local factors like available wind and solar resources that may vary widely. Sudden variability in key components such as solar PV panels may also be a factor.

Solar PV Feed-In Tariff Comparison

Country	Application	Size	Contract Term	€ cents /kWh	US cents /kWh
Germany	Roof-mounted	≤ 30 kW	20	43	61.1
		30 - 100 kW	20	41	58.1
		> 100 kW	20	40	56.2
		> 1,000 kW	20	33	46.9
	Ground-mounted	All sizes	20	32	45.4
Spain	Rooftop	≤ 20 kW	Yr 1 - 25	34	48.3
		> 20 kW	Yr 1 - 25	32	45.4
	Ground-mounted		Yr 1 - 25	32	45.4
Slovenia	Rooftop	≤ 50 kW	15	42	59.0
		> 50 kW - ≤ 1 MW	15	38	54.0
		> 1 MW - ≤ 10 MW	15	32	44.8
	Building Integrated	≤ 50 kW	15	48	67.8

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[21] http://psb.vermont.gov/docketsandprojects/electric/7523/costanalysis under the "Materials" section of the web page.

[22] While rates between the Euro and the Dollar (Dollars/Euro) are only down less than 5% from a year prior (1.49 Dollars/Euro on August 12, 2008 to 1.42 Dollar/Euro on August 12, 2009) they have risen almost 11% over the last 6 months (1.28 Dollars/Euro on February 12, 2009 to 1.42 Dollars/Euro on August 12, 2009) making the cost in the US market more expensive during the latter period. See http://finance.yahoo.com/echarts?s=EURUSD=X#chart2:symbol=eurusd=x;range=2y;indicator=volume;charttype=line;crosshair=on;ohlcvalues=0;logscale=on;source=undefined.

		> 50 kW - ≤ 1 MW	15	44	62.1
		> 1 MW - ≤ 10 MW	15	36	51.5
	Ground-mounted	≤ 50 kW	15	39	55.4
		> 50 kW - ≤ 1 MW	15	36	51.1
		> 1 MW - ≤ 10 MW	15	29	41.2
Switzerland	Rooftop	≤ 10 kW	25	75	69.2
		> 10 kW - ≤ 30 kW	25	65	60.0
		> 30 kW - ≤ 100 kW	25	62	57.2
		> 100 kW	25	60	55.4
	Ground-mounted	≤ 10 kW	25	65	60.0
		> 10 kW - ≤ 30 kW	25	54	49.9
		> 30 kW - ≤ 100 kW	25	51	47.1
		> 100 kW	25	49	45.2
	Building Integrated	≤ 10 kW	25	90	83.1
		> 10 kW - ≤ 30 kW	25	74	68.3
		> 30 kW - ≤ 100 kW	25	67	61.9
		> 100 kW	25	62	57.2
Ontario	Any type	≤ 10 kW	20	80.2	73.31
	Rooftop	> 10 kW - ≤ 250 kW	20	71.3	65.18
		> 250 kW - ≤500 kW	20	63.5	58.05
		> 500 kW	20	53.9	49.27
Gainesville, FL	Ground-mounted	≤ 10 MW	20	44.3	40.49
	all	all	??	32.00	32.00
Vermont Act 45					30.0

Wind Feed-in Tariff Comparison

Country	Size	Contract Term	Reference Yield	€ cents /kWh	US cents /kWh
Germany		First 5 Yrs		9.2	13.06
		Yr 6 - 20*		5.0	7.13
		Wtd Ave**		7.0	10.01
Spain		Yr 1- 20		7.3	10.40
		> 20 Yrs		6.1	8.69
Slovenia		15		9.5	13.54
Switzerland	< 10 kW	20		20.0	18.46
	> 10 kW	20	80%	20.0	18.46
		18.3	90%	20.0	18.46

		16.1	100%	20.0	18.46
		13.9	110%	20.0	18.46
		11.7	120%	20.0	18.46
		9.4	130%	20.0	18.46
		7.2	140%	20.0	18.46
		5	150%	20.0	18.46
		Afterwards to year 20		17.0	15.69
Ontario***		20		13.5	12.72
Vermont Act 45	≤ 15 kW				20
Vermont Act 45	> 15 kW - ≤ 2.2 MW				12.5

Hydro Feed-in Tariff Comparison

Country	Application	Size	Contract Term	€ cents /kWh	US cents /kWh
Germany	New	≤ 500 kW	20	12.67	17.99
		0.5 - 2 MW	20	8.65	12.28
		2 - 5 MW	20	7.65	10.86
	Refurbished	≤ 500 kW	20	11.67	16.57
		0.5 - 2 MW	20	8.65	12.28
		2 - 5 MW	20	8.65	12.28
	Renewal*	≤ 500 kW	15	7.29	10.35
		0.5 - 10 MW	15	6.32	8.97
Spain		< 10 MW	Yr 1 - 25	7.80	11.08
			> 25	7.02	9.97
Slovenia		≤ 50 kW	15	10.55	14.98
		> 50 kW - ≤ 1 MW	15	9.26	13.15
		> 1 MW - ≤ 10 MW	15	8.23	11.69
Switzerland**		≤ 10 kW	20	26.00	24.00
		> 10 kW - ≤ 50 kW	20	20.00	18.46
		> 50 kW - ≤ 300 kW	20	14.50	13.39
		> 300 kW - ≤ 1 MW	20	11.00	10.15
		> 1 MW - ≤ 10 MW	20	7.50	6.92
Ontario		≤ 10 MW	20	13.10	12.34
Vermont Act 45					12.28

Biomass Feed-in Tariff Comparison

Country	Size	Application	Contract Term	€ cents /kWh	US cents /kWh
Germany	≤ 150 kW	Biomass excl. biogas	20	11.67	16.57
		Biomass excl. biogas*	20	17.67	25.09
		biogas*	20	18.67	26.51
		biogas w/ 30% manure slurry*	20	15.67	22.25
		biogas w/ landscape material	20	13.67	19.41
	0.150 kW - 500 kW	Biomass	20	9.18	13.04
		Solid Biomass*	20	15.18	21.56
		liquid Biomass*	20	9.18	13.04
		Gas Biomass*	20	15.18	21.56
		Biogas*	20	16.18	22.98
		biogas w/ 30% manure slurry*	20	10.18	14.46
		biogas w/ landscape material	20	11.18	15.88
	.5 MW - 5 MW	Biomass	20	8.25	11.72
		Solid Biomass*	20	12.25	17.40
		liquid Biomass*	20	8.25	11.72
		Gas Biomass*	20	12.25	17.40
		Wood Combustion*	20	10.75	15.27
		Wood (coppice & landscape)*	20	12.25	17.40
		Gas reprocessing ≤ 350 nM3/hr	20	10.25	14.56
		Gas reprocessing ≤ 700 nM3/hr	20	9.25	13.14
Spain	≤ 2 MW	Energy Crops	Yr 1-15	15.89	22.56
			> 15	11.79	16.75
			Wtd Ave**	15.53	22.06
		Agricultural Wastes	Yr 1-15	12.57	17.85
			> 15	8.48	12.03
			Wtd Ave**	12.21	17.34
		Forestry Wastes	Yr 1-15	12.57	17.85
			> 15	8.48	12.03
			Wtd Ave**	12.21	17.34
		Forestry Wastes from Industry	Yr 1-15	9.28	13.18
			> 15	6.51	9.24
			Wtd Ave**	9.04	12.83
	All Project Sizes	Landfill Gas	Yr 1-15	7.99	11.35
			> 15	6.51	9.24
			Wtd Ave**	7.86	11.17
	≤ .5 MW	Gas from Anaerobic Digestion	Yr 1-15	13.07	18.56
			> 15	6.51	9.24

			Wtd Ave**	12.50	17.75
	> .5 MW	Gas from Anaerobic Digestion	Yr 1-15	9.68	13.75
			> 15	6.51	9.24
			Wtd Ave**	9.40	13.35
	All Project Sizes	Liquid Biofuels	Yr 1-15	5.36	7.61
			> 15	5.36	7.61
			Wtd Ave**	5.36	7.61
	> 2 MW	Energy Crops	Yr 1-15	14.66	20.82
			> 15	12.35	17.53
			Wtd Ave**	14.46	20.53
		Agricultural Wastes	Yr 1-15	10.75	15.27
			> 15	8.07	11.45
			Wtd Ave**	10.52	14.94
		Forestry Wastes	Yr 1-15	11.83	16.80
			> 15	8.07	11.45
			Wtd Ave**	11.50	16.33
		Forestry Wastes from Industry	Yr 1-15	6.51	9.24
			> 15	6.51	9.24
			Wtd Ave**	6.51	9.24
		Black Liquor	Yr 1-15	8.00	11.36
			> 15	6.51	9.24
			Wtd Ave**	7.87	11.18
Slovenia	> 50 kW - ≤ 1 MW	Wood Biomass	15	22.44	31.86
	> 1 MW - ≤ 10 MW		15	16.74	23.78
	≤ 50 kW	Biogas-Biomass	15	16.01	22.73
	> 50 kW - ≤ 1 MW		15	15.58	22.12
	> 1 MW - ≤ 10 MW		15	14.08	19.99
	≤ 50 kW	Biogas-Waste	15	13.92	19.77
	> 50 kW - ≤ 1 MW		15	13.92	19.77
	> 1 MW - ≤ 10 MW		15	12.92	18.34
	≤ 50 kW	Landfill Gas	15	9.93	14.10
	> 50 kW - ≤ 1 MW		15	6.75	9.58
	> 1 MW - ≤ 10 MW		15	6.17	8.76
	≤ 50 kW	Sewage Gas	15	8.58	12.19
	> 50 kW - ≤ 1 MW		15	7.44	10.57
	> 1 MW - ≤ 10 MW		15	6.61	9.38
	> 50 kW - ≤ 1 MW	Biodegradable Wastes	15	7.74	11.00
	> 1 MW - ≤ 10 MW		15	7.43	10.56
Switzerland		Sewage Gas	20	24.00	22.16
		Waste Gas	20	20.00	18.46

	≤ 50 kW	Other Biogas	20	24.00	22.16
	> 50 kW - ≤ 100 kW		20	21.50	19.85
	> 100 kW - ≤ 500 kW		20	19.00	17.54
	> 500 kW - ≤ 5 MW		20	16.00	14.77
	≤ 50 kW	Biogas w/ Ag Waste	20	39.00	36.00
	> 50 kW - ≤ 100 kW		20	35.00	32.31
	> 100 kW - ≤ 500 kW		20	30.00	27.69
	> 500 kW - ≤ 5 MW		20	20.00	18.46
Ontario***	≤ 10 MW	Biomass	20	13.80	13.00
Vermont Act 45	≤ 2.2 MW	Methane from Landfill or Ag			12.00
Vermont Act 45	≤ 2.2 MW	Other Biomass			12.5

Farm Biomass Feed-in Tariff Comparison

Country	Size	Application	Contract Term	€ cents /kWh	US cents /kWh
Germany	≤ 150 kW	biogas w/ 30% manure slurry*	20	15.67	22.25
	0.150 kW - 500 kW	biogas w/ 30% manure slurry*	20	10.18	14.46
Spain	≤ .5 MW	Gas from Anaerobic Digestion	Yr 1-15	13.07	18.56
			> 15	6.51	9.24
			Wtd Ave**	12.50	17.75
	> .5 MW		Yr 1-15	9.68	13.75
			> 15	6.51	9.24
			Wtd Ave**	9.40	13.35
Slovenia	≤ 50 kW	Biogas-Biomass	15	16.01	22.73
	> 50 kW - ≤ 1 MW		15	15.58	22.12
	> 1 MW - ≤ 10 MW		15	14.08	19.99
	≤ 50 kW	Biogas-Waste	15	13.92	19.77
	> 50 kW - ≤ 1 MW		15	13.92	19.77
	> 1 MW - ≤ 10 MW		15	12.92	18.34
	> 50 kW - ≤ 1 MW	Biodegradable Wastes	15	7.74	11.00
	> 1 MW - ≤ 10 MW		15	7.43	10.56
Switzerland	≤ 50 kW	Other Biogas	20	24.00	22.16
	> 50 kW - ≤ 100 kW		20	21.50	19.85
	> 100 kW - ≤ 500 kW		20	19.00	17.54
	> 500 kW - ≤ 5 MW		20	16.00	14.77
	≤ 50 kW	Biogas w/ Ag Waste	20	39.00	36.00
	> 50 kW - ≤ 100 kW		20	35.00	32.31
	> 100 kW - ≤ 500 kW		20	30.00	27.69

	> 500 kW - ≤ 5 MW		20	20.00	18.46
Ontario***	≤ 100 kW	On-Farm	20	19.50	18.37
	> 100 kW - ≤ 250 kW		20	18.50	17.43
	≤ 500 kW	Other Biogas	20	16.00	15.07
	> 500 kW - ≤ 10 MW		20	14.70	13.85
Vermont Act 45	≤ 50 kW				12.00

Landfill Gas Feed-in Tariff Comparison

Country	Size	Application	Contract Term	€ cents /kWh	US cents /kWh
Germany	≤ 150 kW	Biomass	20	11.67	16.57
	0.150 kW - 500 kW	Biomass	20	9.18	13.04
		Gas Biomass*	20	15.18	21.56
	.5 MW - 5 MW	Biomass	20	8.25	11.72
		Gas Biomass*	20	12.25	17.40
Spain	All Project Sizes	Landfill Gas	Yr 1-15	7.99	11.35
			> 15	6.51	9.24
			Wtd Ave**	7.86	11.17
Slovenia	≤ 50 kW	Landfill Gas	15	9.93	14.10
	> 50 kW - ≤ 1 MW		15	6.75	9.58
	> 1 MW - ≤ 10 MW		15	6.17	8.76
Switzerland		Sewage Gas	20	24.00	22.16
		Waste Gas	20	20.00	18.46
	≤ 50 kW	Other Biogas	20	24.00	22.16
	> 50 kW - ≤ 100 kW		20	21.50	19.85
	> 100 kW - ≤ 500 kW		20	19.00	17.54
	> 500 kW - ≤ 5 MW		20	16.00	14.77
Ontario***	≤ 10 kW	Landfill Gas	20	11.10	10.46
Vermont Act 45					12.00

Appendix D -- Cost Analysis Subgroup Participants

The following individuals (along with their affiliation) participated at the meetings or via phone on at least one of the seven meetings held by the Cost Analysis Subgroup.

Aldrich, Jon – International Business Machines
Allen, Riley – Vermont Public Service Board
Basa, William - Northern Power Systems
Becker, John – Vermont Department of Public Service
Beinecke, Ben - Northern Power Systems
Callendrello, Tony - BayCorp Holdings
Dalton, John - Power Advisory LLC
Foley, Sean – Vermont Department of Public Service
Hosie, Ron - Longview Infrastructure LLC
Jones, Ken – Vermont Department of Taxes
Krolewski, Mary Jo – Vermont Public Service Board
Kvedar, Tony – Green Mountain Power
Laber, Gregg - Green Mtn Elec Supply
Lamont, Dave – Vermont Department of Public Service
McManus, David - Delta Energy Group
Mutty, Christopher - Encore Redevelopment
Perchlik, Andrew - Renewable Energy Vermont
Raker, Mike- Agricultural Energy Consultants, LLC
Rickerson, Wilson – Meister Consultant's Group
Scruton, Dan – Vermont Agency of Agriculture
Swanson, Sam - VTIPL

Appendix E – Description of Interconnection Facilities Related to Distributed Generation

Description of Interconnection Costs (provided courtesy of CVPS)

Interconnection costs are a component of all projects and developers were asked to include an estimate of such costs in their estimates of costs. The following provides context for this category of costs, and the initial draft was provided by CVPS personnel.

Projects undertaken for the feed in tariff will possibly run the gamut from 1 kW PV installed in someone's front yard to a 2.2 MW CHP plant located miles from nowhere. Interconnection requirements can (and will) vary greatly over this range. Some requirements are independent of generation technology while some may be dependent.

Interconnection requirements may be as simple as a revenue grade meter and a low cost, secondary voltage disconnect switch or as involved as sophisticated metering packages, real time communications, special protection schemes ("SPS"), and a primary voltage airbreak switch. These requirements are determined by such things as the size of the proposed DG, the strength of the distribution line to which the DG will interconnect, the topology of the distribution circuit, and the aggregation of additional DG on the circuit. As mentioned above, the DG technology itself may also come into play. It is safe to say that the complexity of the interconnection requirements will typically increase as DG size (individual and in aggregate) increases.

Smaller projects will require a meter, whereas larger projects may require a primary metering package made up of not only the meter but also meter instrument transformers (CT's and PT's). The meter for larger projects is also more costly and has additional functionality not found in basic small project meters. Real time or remote access through communication capability to enable daily reads may also be necessary for settlement purposes. The preliminary results of the Settlement Subgroup suggest that such communications capabilities will be generally required above a certain resource size.

Smaller projects may be able to interconnect to an existing transformer feeding a customer's home or business. Larger projects will need to purchase and own their own transformer (referred to as a Generator Step Up transformer or GSU). These will typically be larger, more costly transformers.

Smaller projects will interconnect at a secondary voltage possibly at a customer's home or business. They may need a service drop or underground secondary service. Larger projects will connect at a primary voltage and may require additional poles, distribution line phase upgrades, and /or a line extension.

Smaller projects will need a disconnect switch that is a lower voltage switch that provides the host utility a visible, lockable means of disconnect (e.g., 60 amp or 200 amp lever operated disconnect). Larger projects will require the disconnect switch to be at the higher primary voltage such as a 3 phase pole top mounted "airbrake" switch.

Smaller projects may use a breaker box or fused disconnect switch. Larger projects will need primary voltage, pole mounted "fused cutouts" to provide fuse protection.

Smaller projects may be able to "fast track" through the Rule 5.500 interconnection process. Larger projects (and some smaller projects proposed for areas that are electrically weak) will require interconnection studies as outlined in Rule 5.500 (e.g., Feasibility Study, System Impact Study, and Facilities Study).

Depending on the combination of DG size, location of distribution protective devices, and load distribution relative to those devices, a "transfer trip" scheme may be required for safety reasons. Other factors, such as distribution system strength, may dictate what GSU configuration is required for three phase interconnections. This may, in turn, require additional equipment.

Transfer Trip

Until recently, there was practically no DG interconnected to distribution utilities. Traditionally, power flowed to customers along radial lines emanating from a substation. When a fault along a line occurred, a protective device (e.g., fuse, recloser, or breaker) would open and isolate the line "downstream" of the device. Since the only source of power was the line from the substation, the customers downstream of the protective device would be without power.

If DG is interconnected on a distribution line downstream of a protective device and is large enough, it can potentially keep the portion of an isolated line energized, thus creating an "island" of energized conductors and customers that should not be energized. Islanding, even for a very short duration (cycles), is an extremely undesirable condition that can lead to damaged equipment and/or injury (or worse) for not only the DG installation but for other customers islanded as well.

One method of precluding this situation is to implement what is called a transfer trip scheme (TT). In a TT, there is communication between the protective device "upstream" of the DG (i.e., between the DG and substation) and the DG. When a fault occurs that causes the protective device to operate, a signal is sent to the DG telling it to trip off-line. This requires that the protective device be capable of generating a logic signal for communication to the DG. The most common protective devices used on distribution circuits in Vermont are fuses and simple, single phase reclosers. Neither of these are capable of generating the necessary logic signal. More sophisticated (and expensive) electronic reclosers (single or three phase) are needed.

So far, CVPS has had to recommend a TT for all five Cow Power™ farm-methane installations developed within our service territory (three that are up and running and two that are still in the study process).

Communication between the protective device and the DG can be achieved in one of three ways: radio, dedicated phone line, dedicated fiber optics. Radio has worked for all CVPS Cow Power™ installations to date, but can be problematic in mountainous areas or over long distances. A combination of radio and fiber optic has been recommended for one of the farms still in the study process. A dedicated phone line is used for a farm outside of the CVPS territory.

Transfer trip components:

Three phase:

Protective device –	Three phase electronic recloser
	Transceiver and antenna (if using radio communications)
DG -	Three phase electronic recloser (due to generator step up transformer configuration)
	Receiver and antenna (if using radio communications)

Single phase:

Protective device –	Single phase electronic recloser
	Transceiver and antenna (if using radio communications)
DG -	Receiver and antenna (if using radio communications)
	(Single phase DG does not have a transformer configuration.)

Depending on the DG size, placement of protective devices on the distribution circuit, and load on the lines downstream of the protective devices, TT may be needed between more than one protective device and the DG. This is the case for one of the farms still in the study phase. For this farm, TT between two protective devices and the DG is needed.

Please note, anti-islanding requirements are based, in large part, on the aggregate DG below a protective device. Thus, the placement of multiple DG units on a circuit may add to the probability of anti-islanding requirements. It is conceivable that some number of small, identically sized DG's could interconnect to a line without requiring any anti-islanding protection yet it would be required for the next identically sized unit due to the aggregate of all the DG.